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WO 98/00626 A US 5348895 A

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(54) Abstract Title

Wellbore casing with radially expanded liner extruded off a mandrel.

(57) A tubular liner 210 and mandrel 205 are positioned within a section of wellbore 100 with the tubular liner overlapping an existing casing 110 (if present). A hardenable fluidic material (305, figure 3) is injected into the section of wellbore 310 below the level of the mandrel 205 and into the annular region 315 between the tubular liner and the section of the wellbore. The inner and outer regions of the tubular liner are then fluidically isolated by introducing a plug 405. A non-hardenable fluidic material 306 is then injected into a portion of the interior of the tubular liner 310, below the mandrel, to pressurize it. The tubular liner is subsequently extruded off of the mandrel.

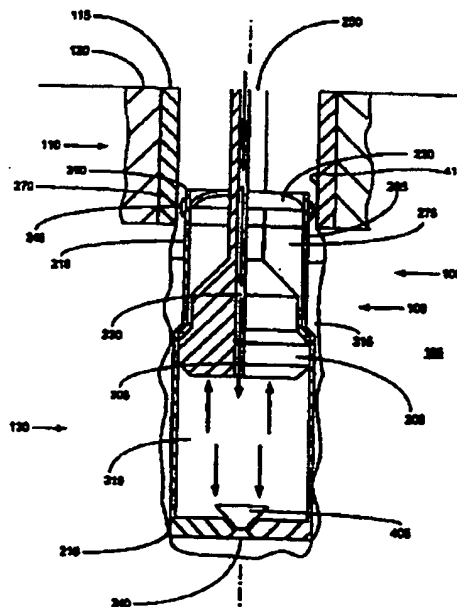


FIGURE 4

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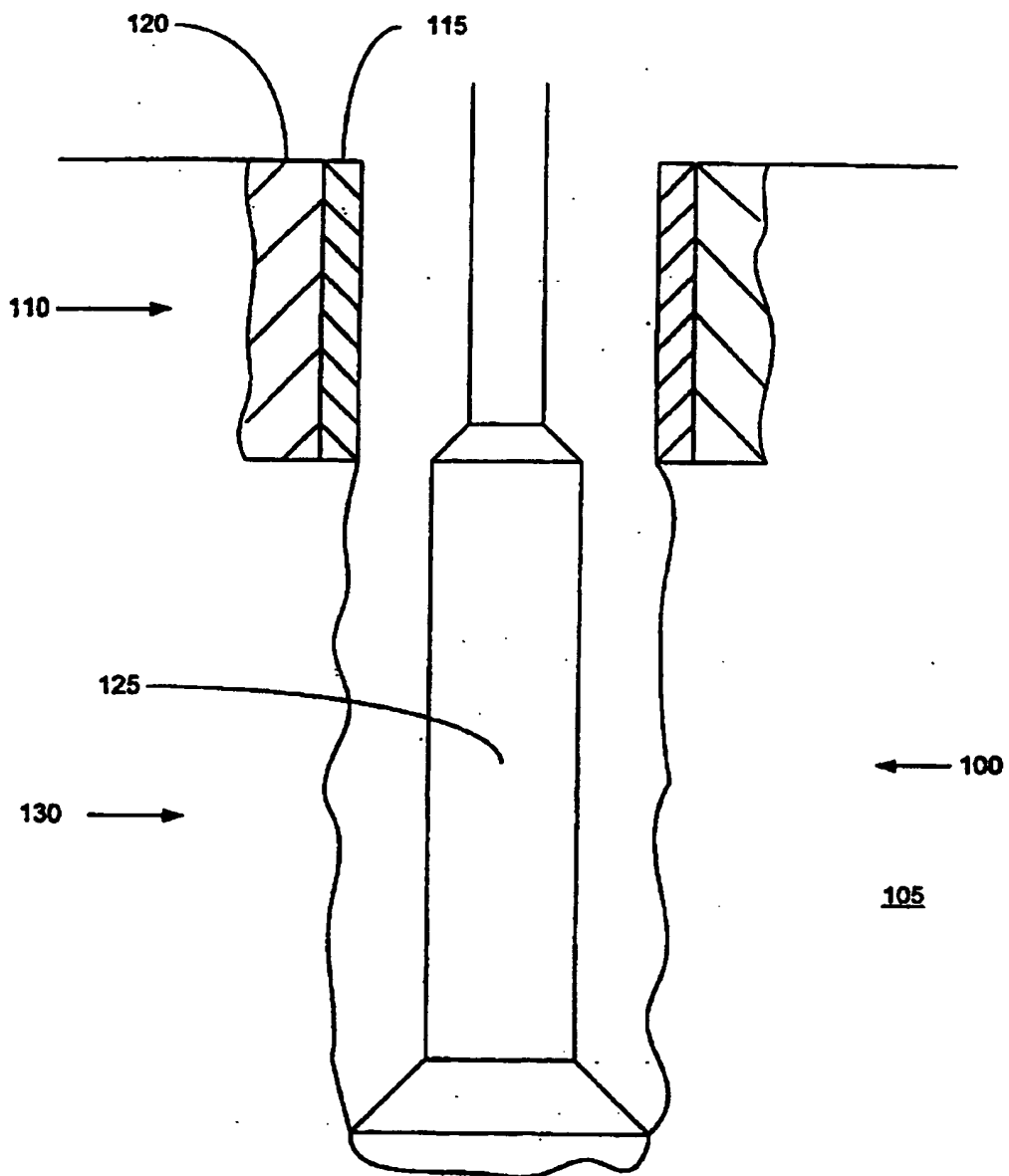


FIGURE 1

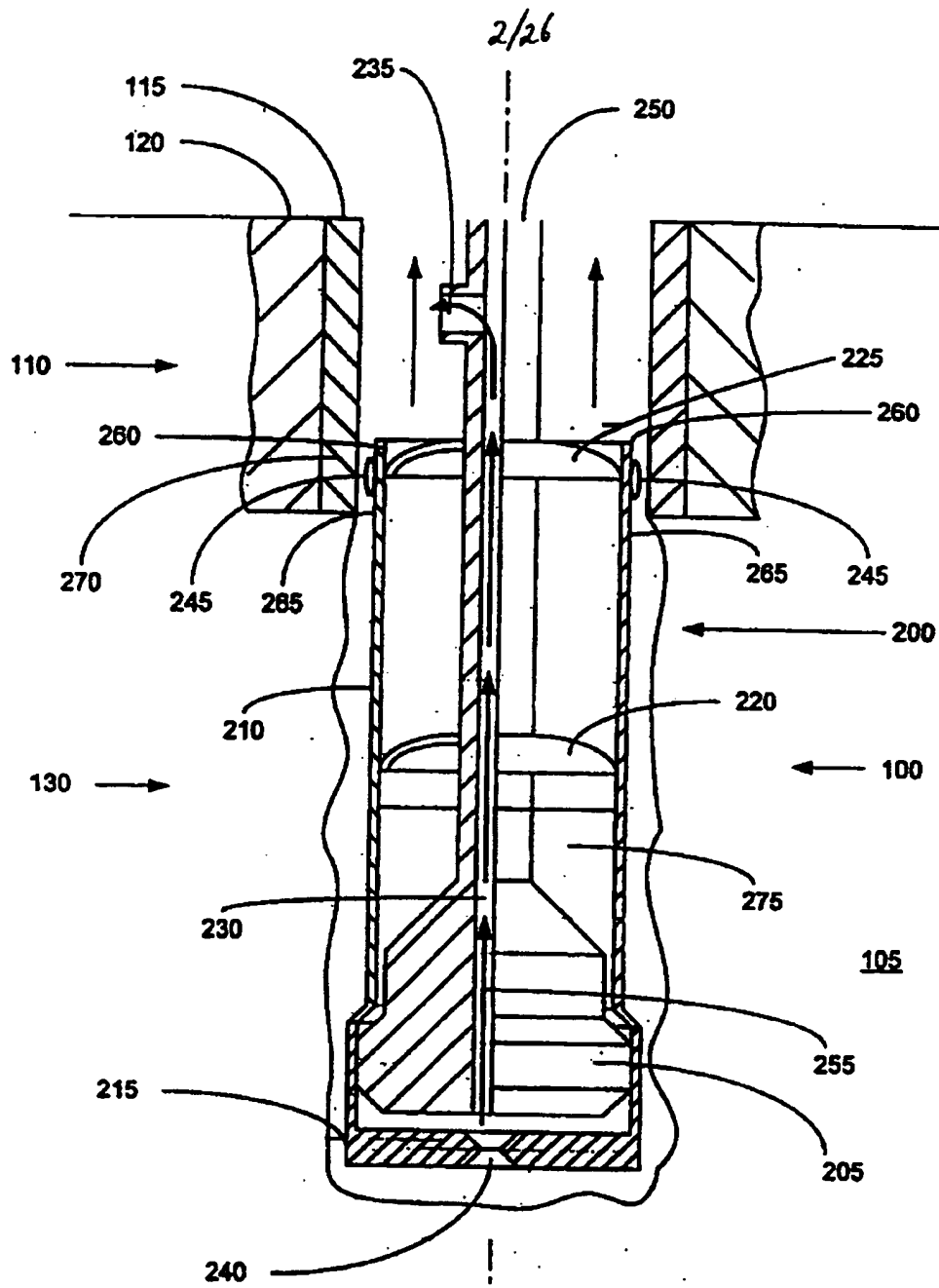


FIGURE 2

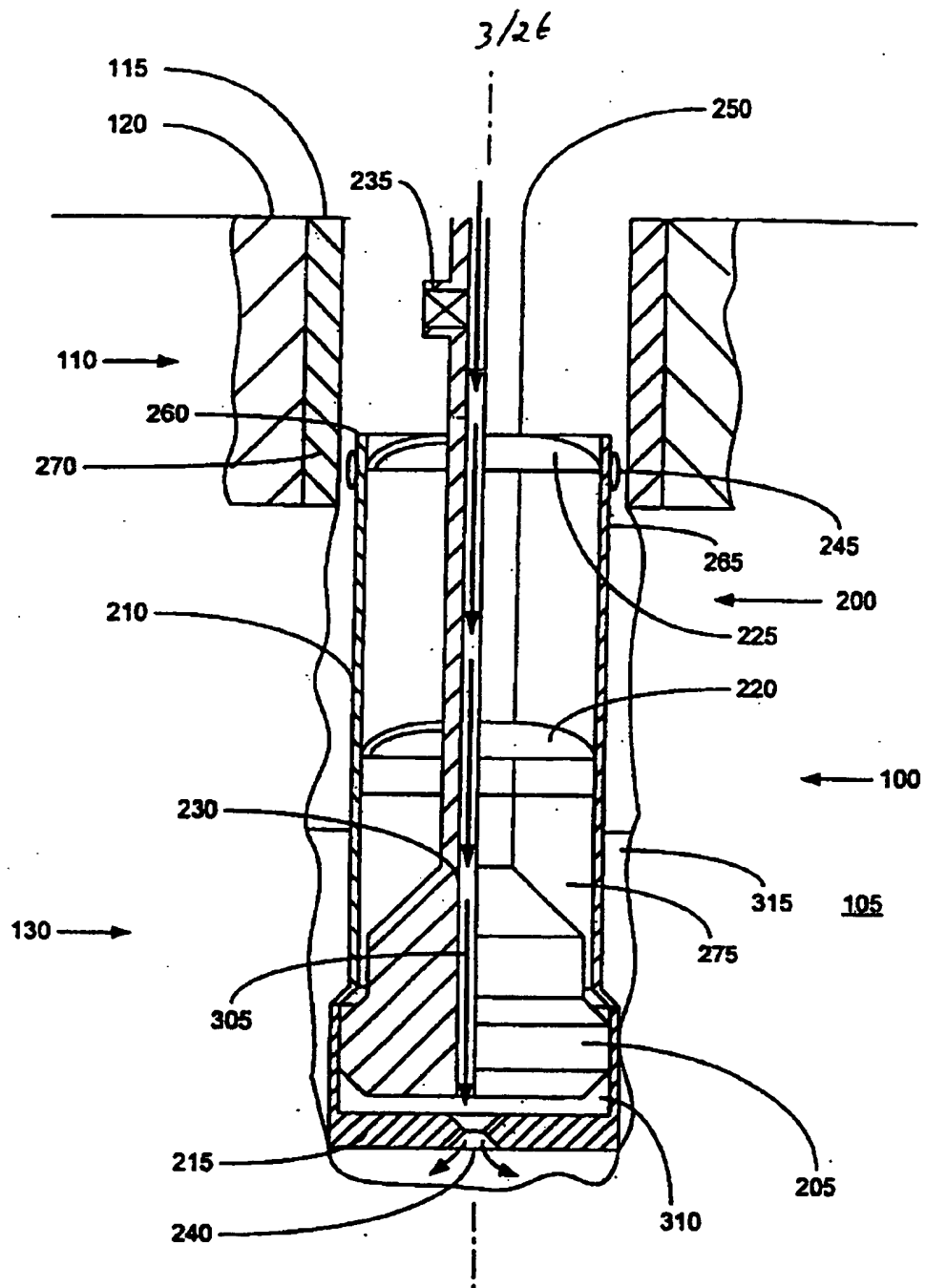


FIGURE 3

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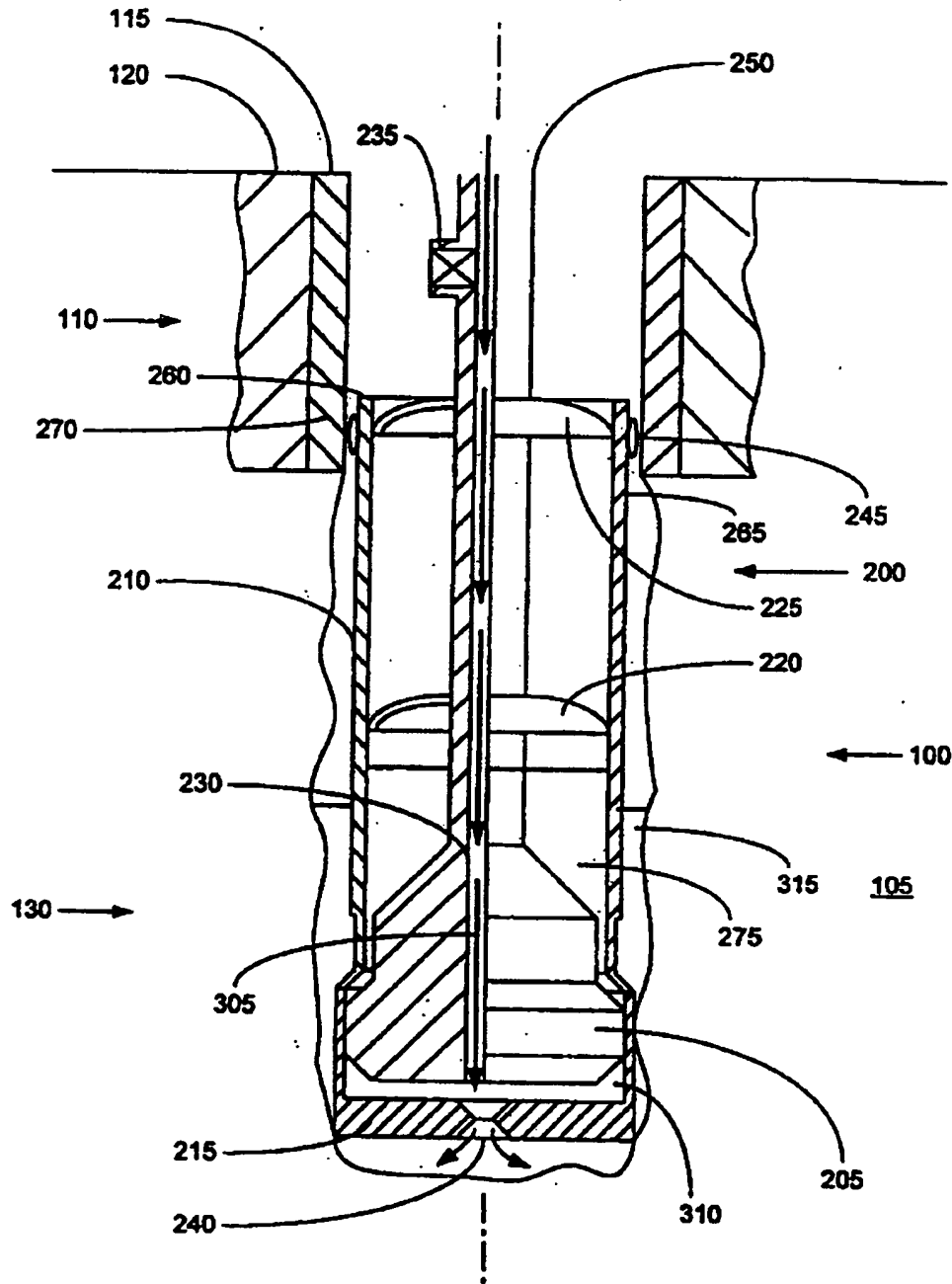


FIGURE 3a

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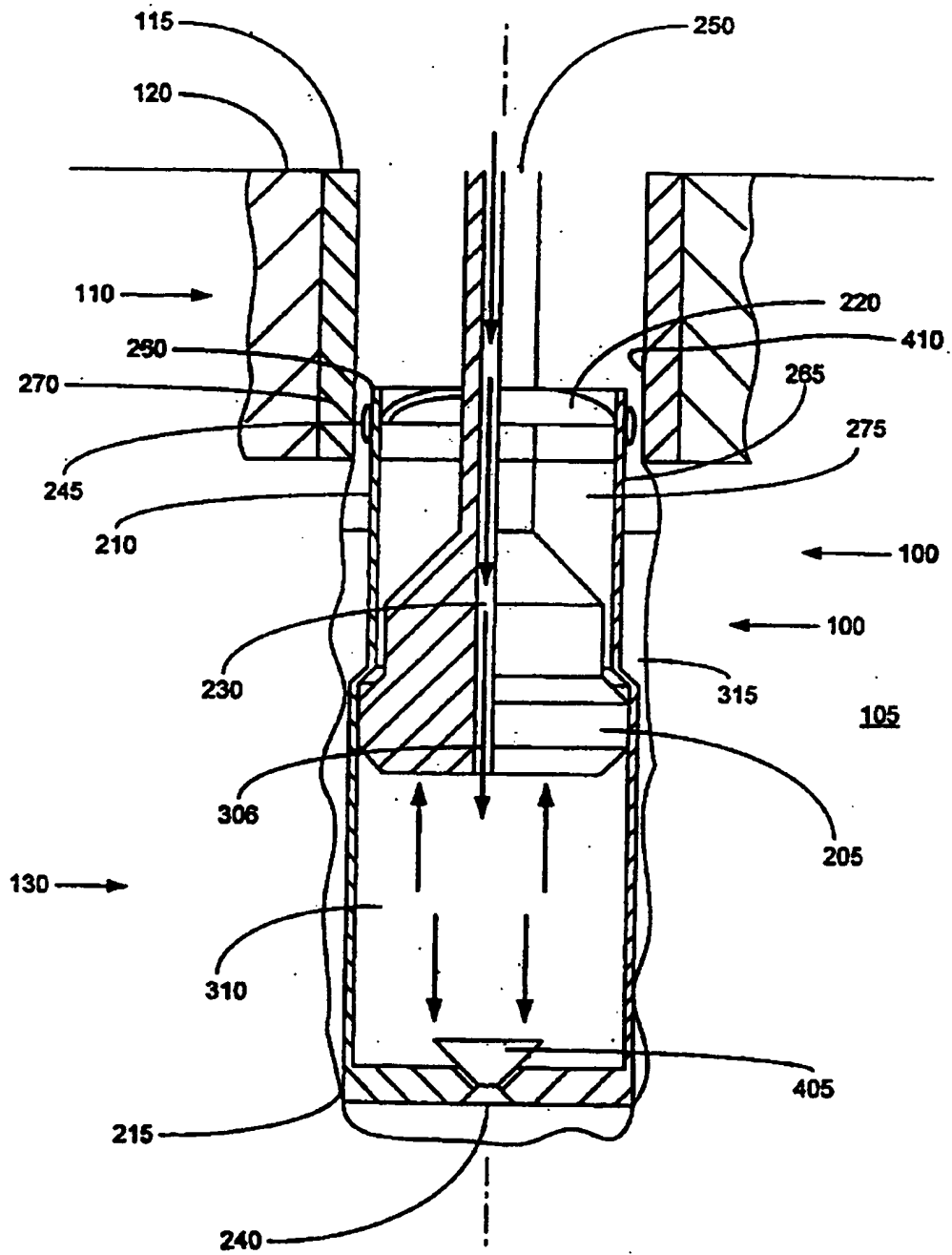


FIGURE 4

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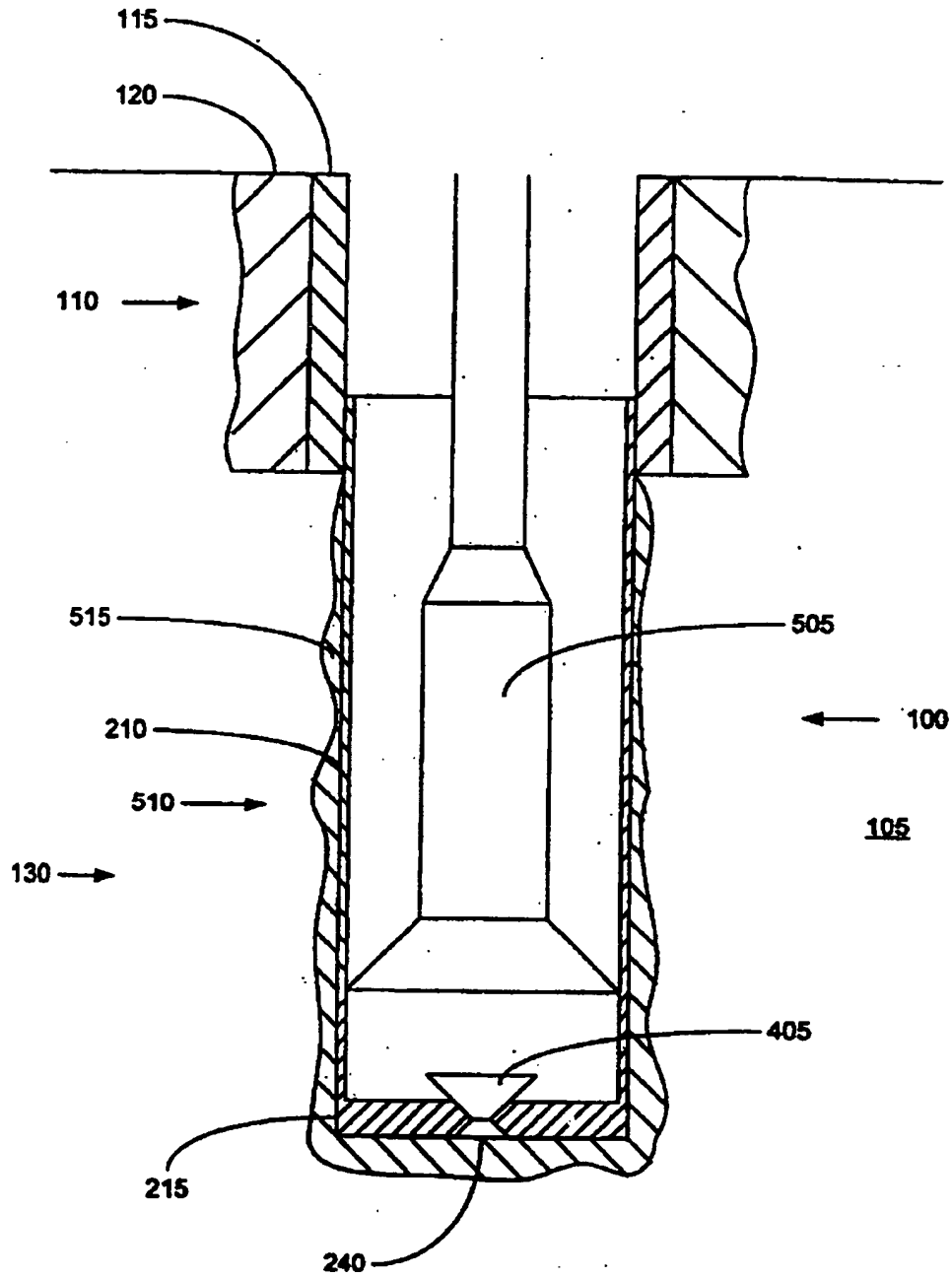


FIGURE 5

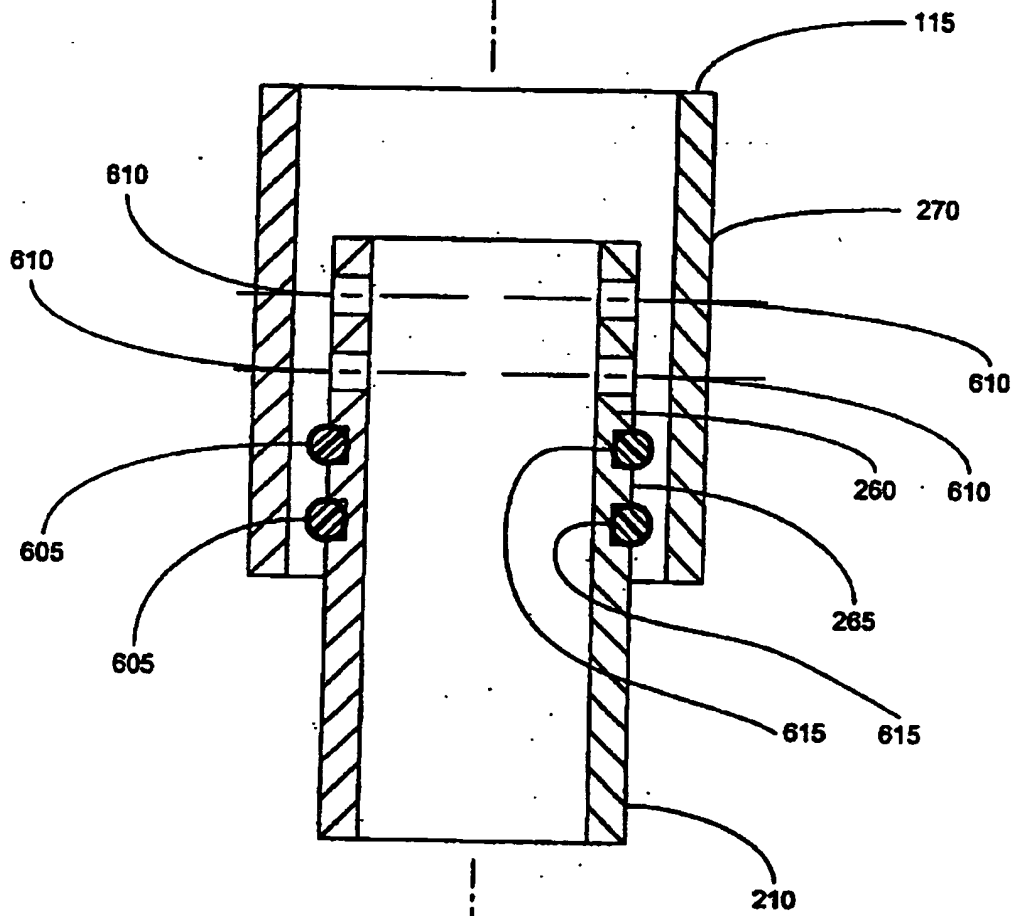


FIGURE 6

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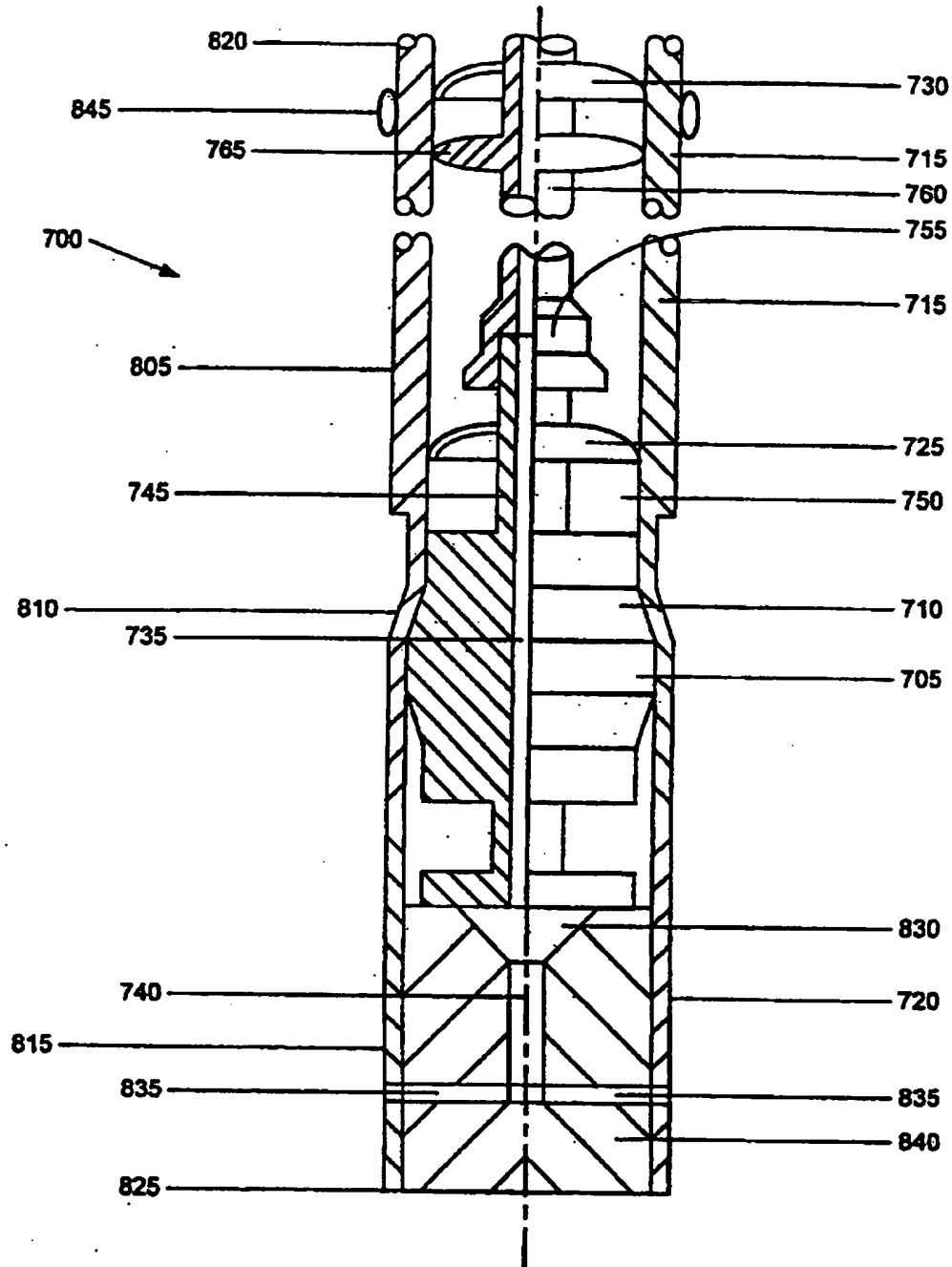


FIGURE 7

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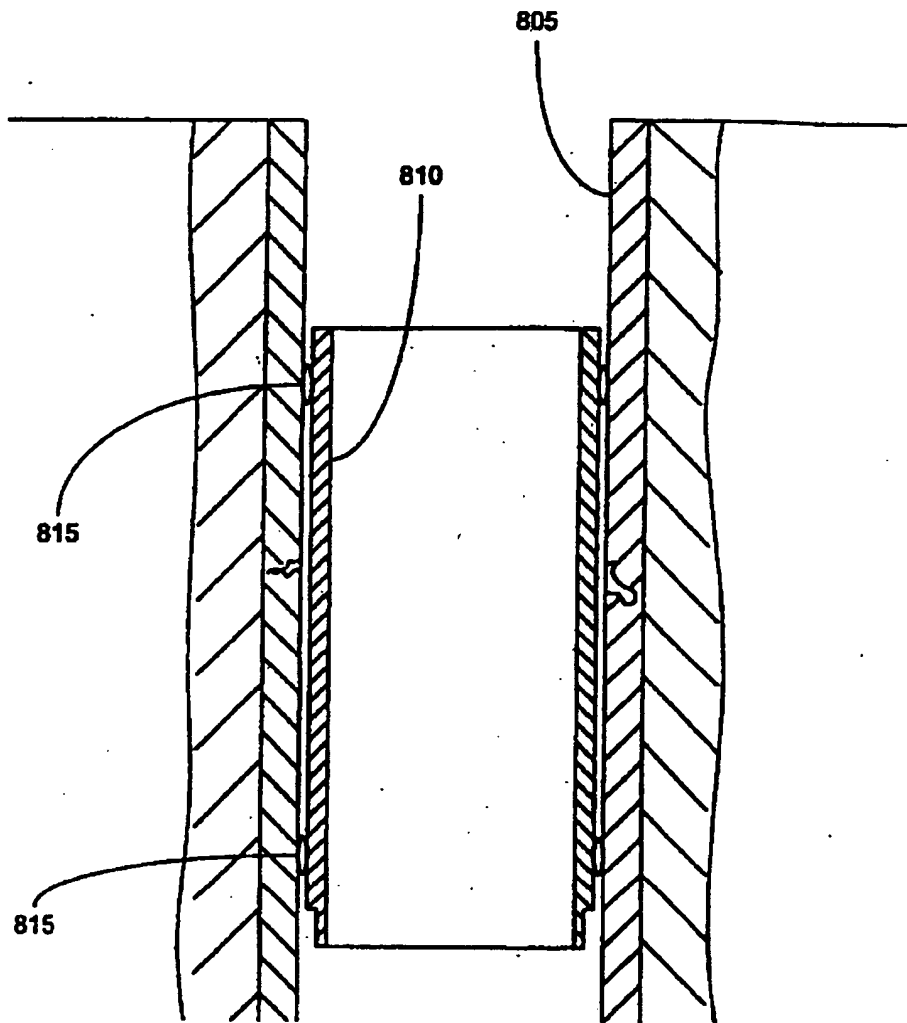


FIGURE 8

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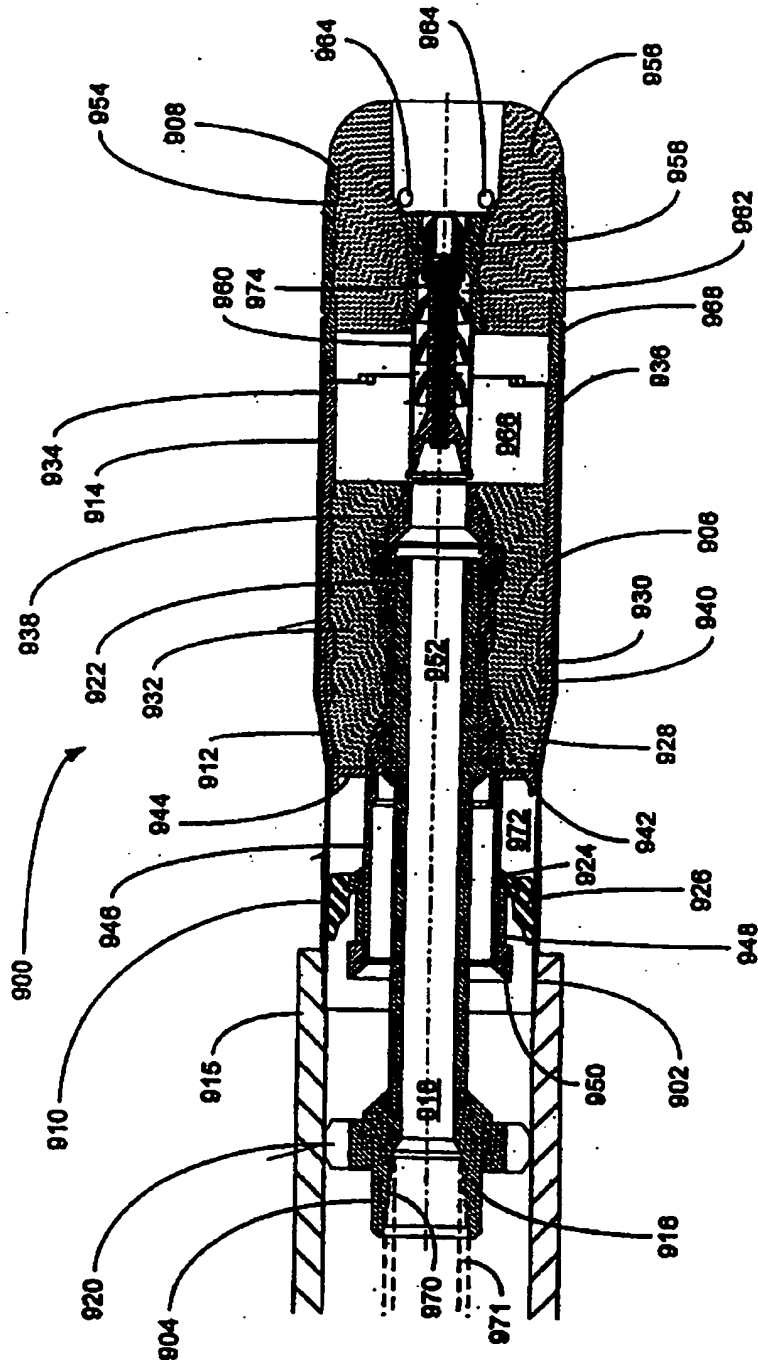


FIGURE 9

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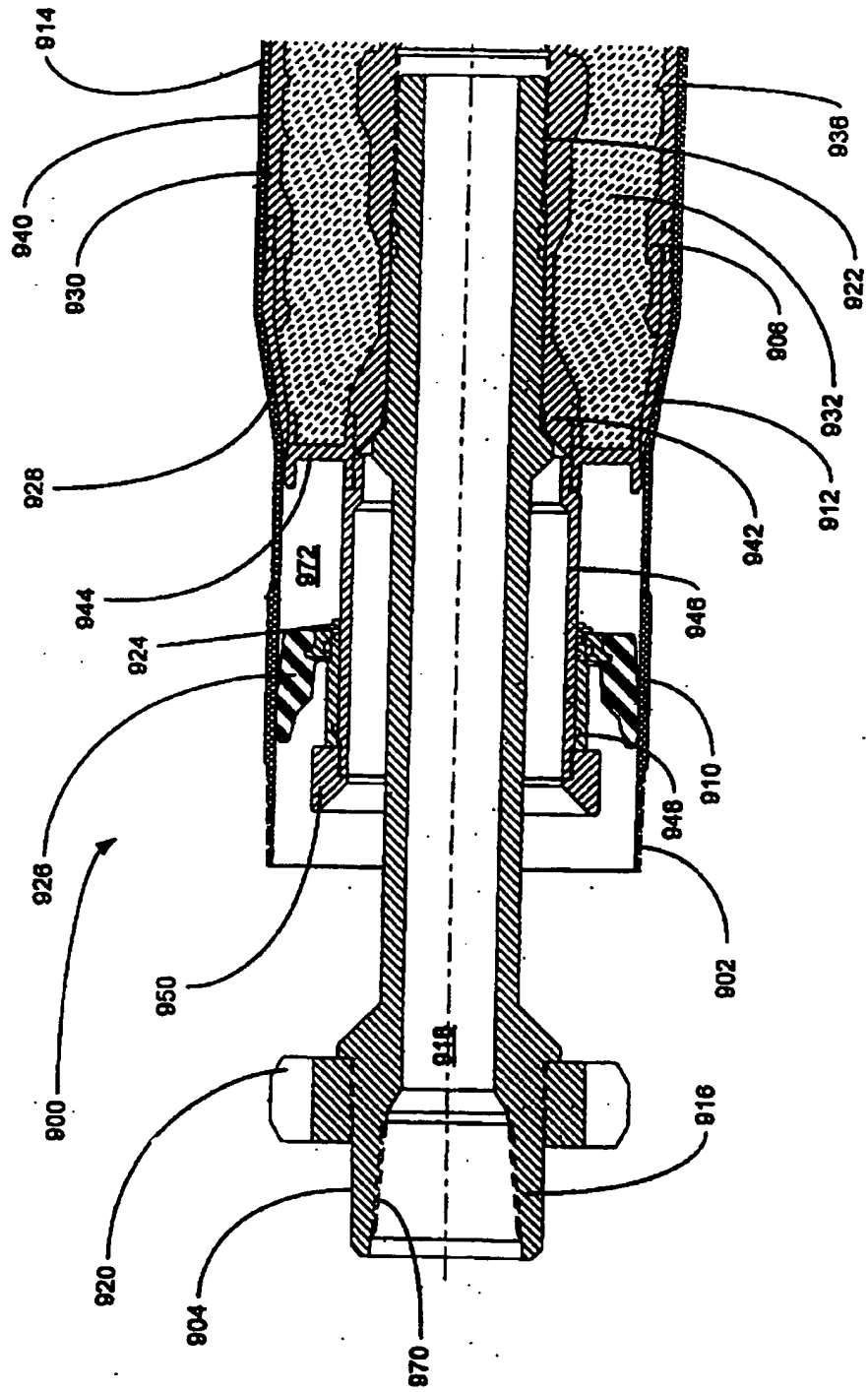


FIGURE 9a

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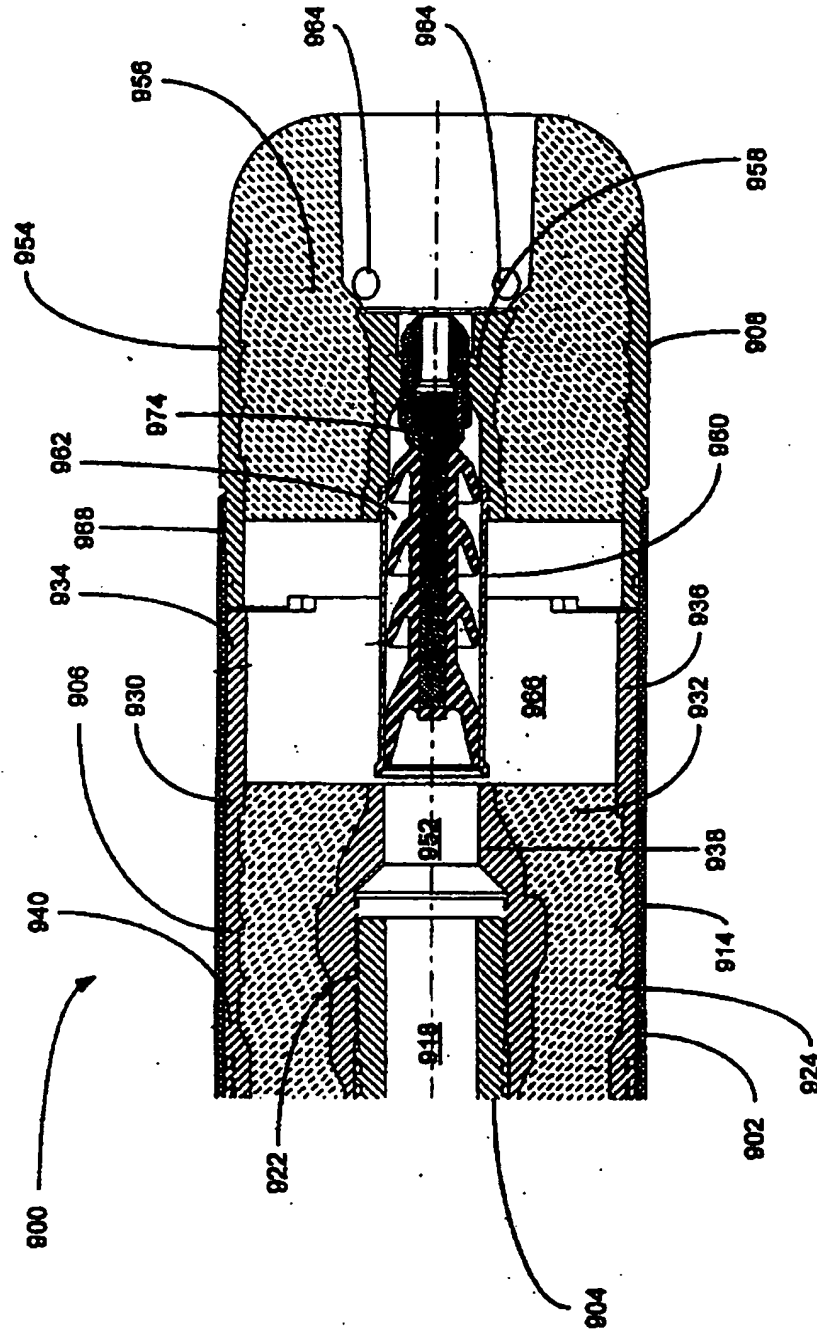


FIGURE 9b

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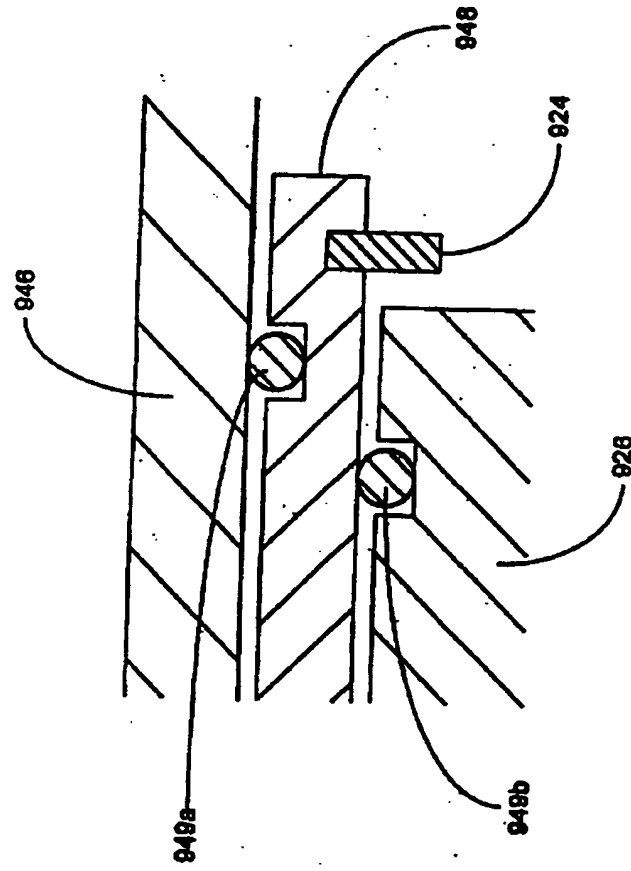


FIGURE 9C

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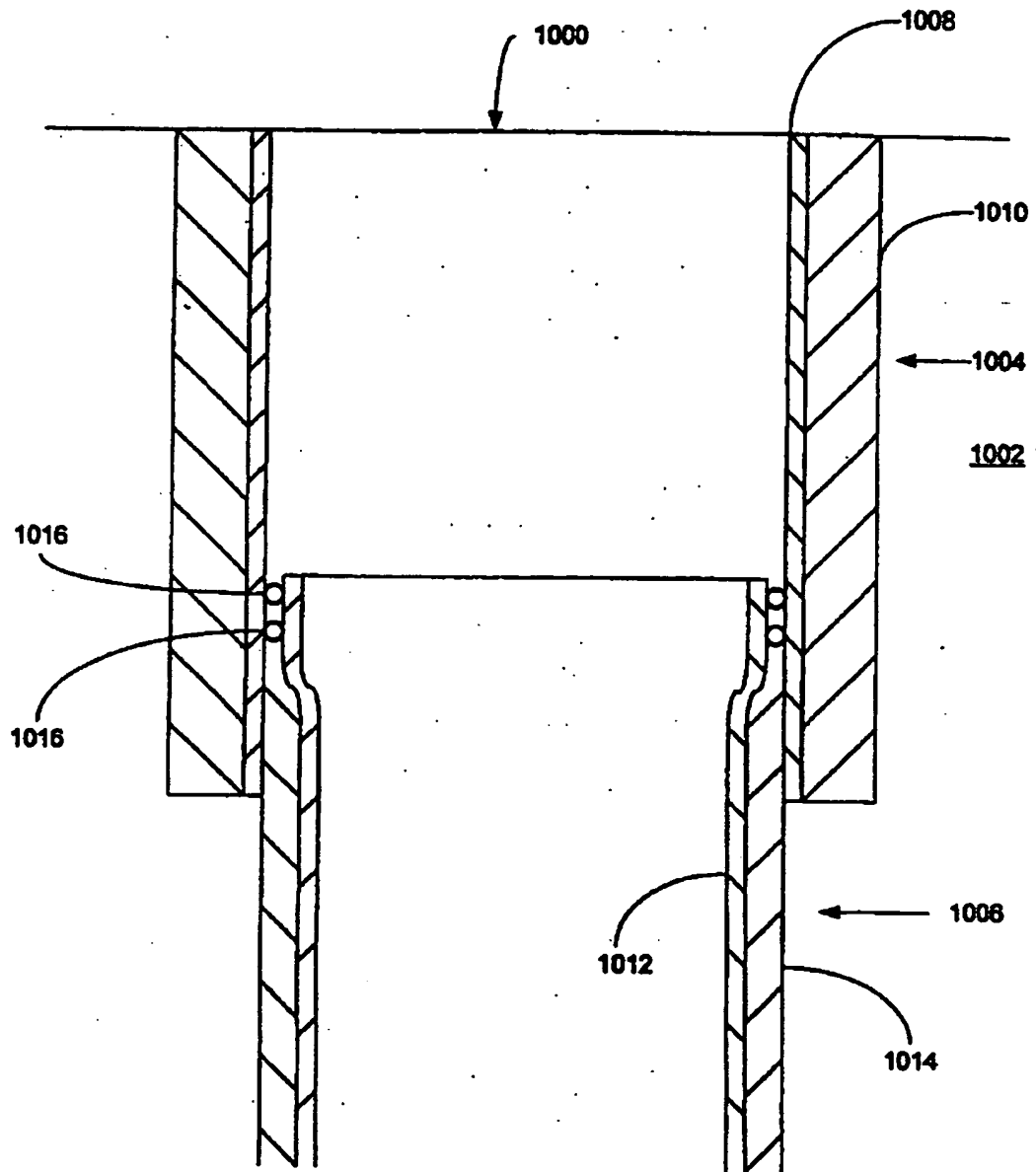


FIGURE 10a

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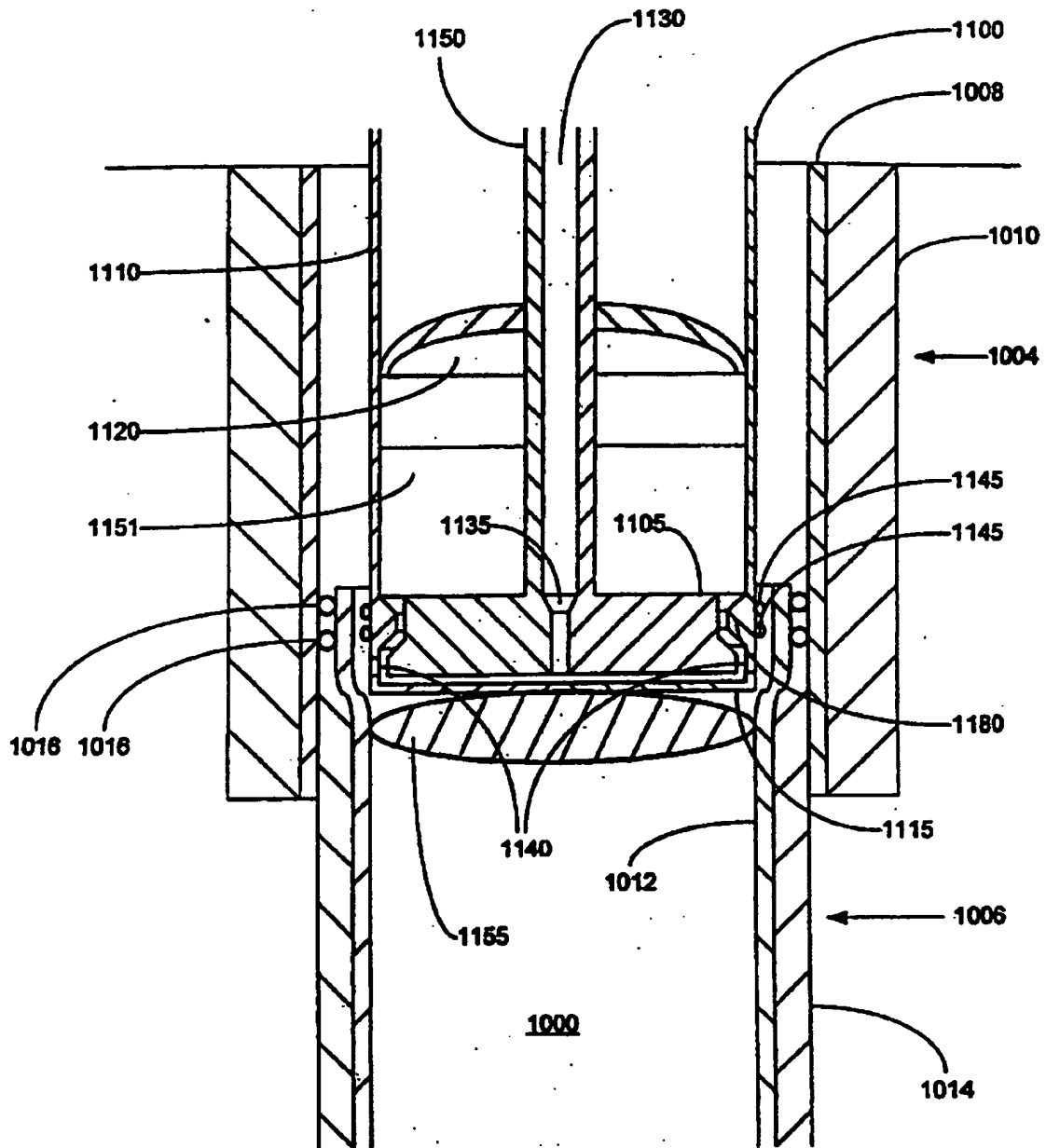


FIGURE 10b

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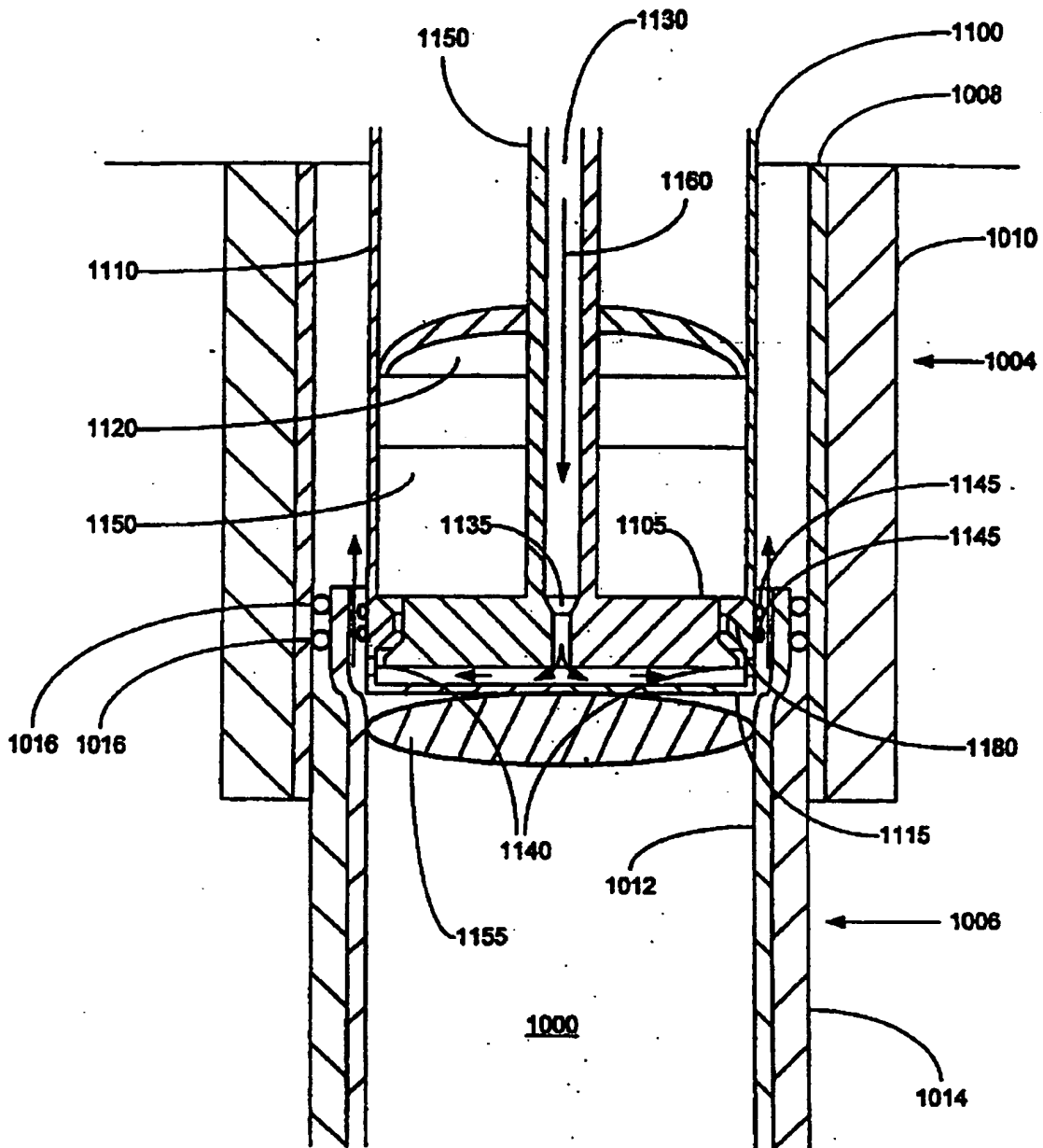


FIGURE 10c

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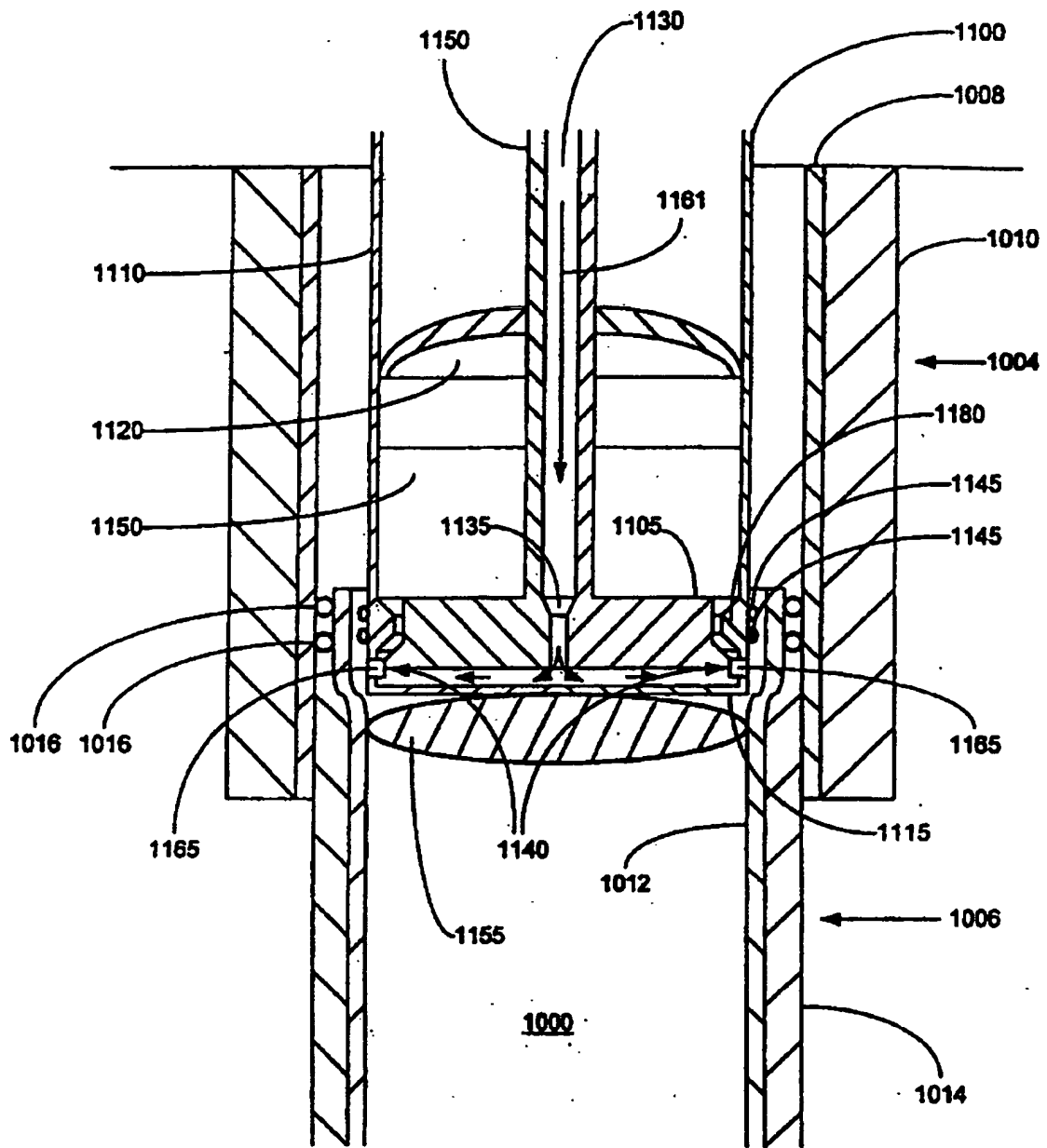


FIGURE 10d

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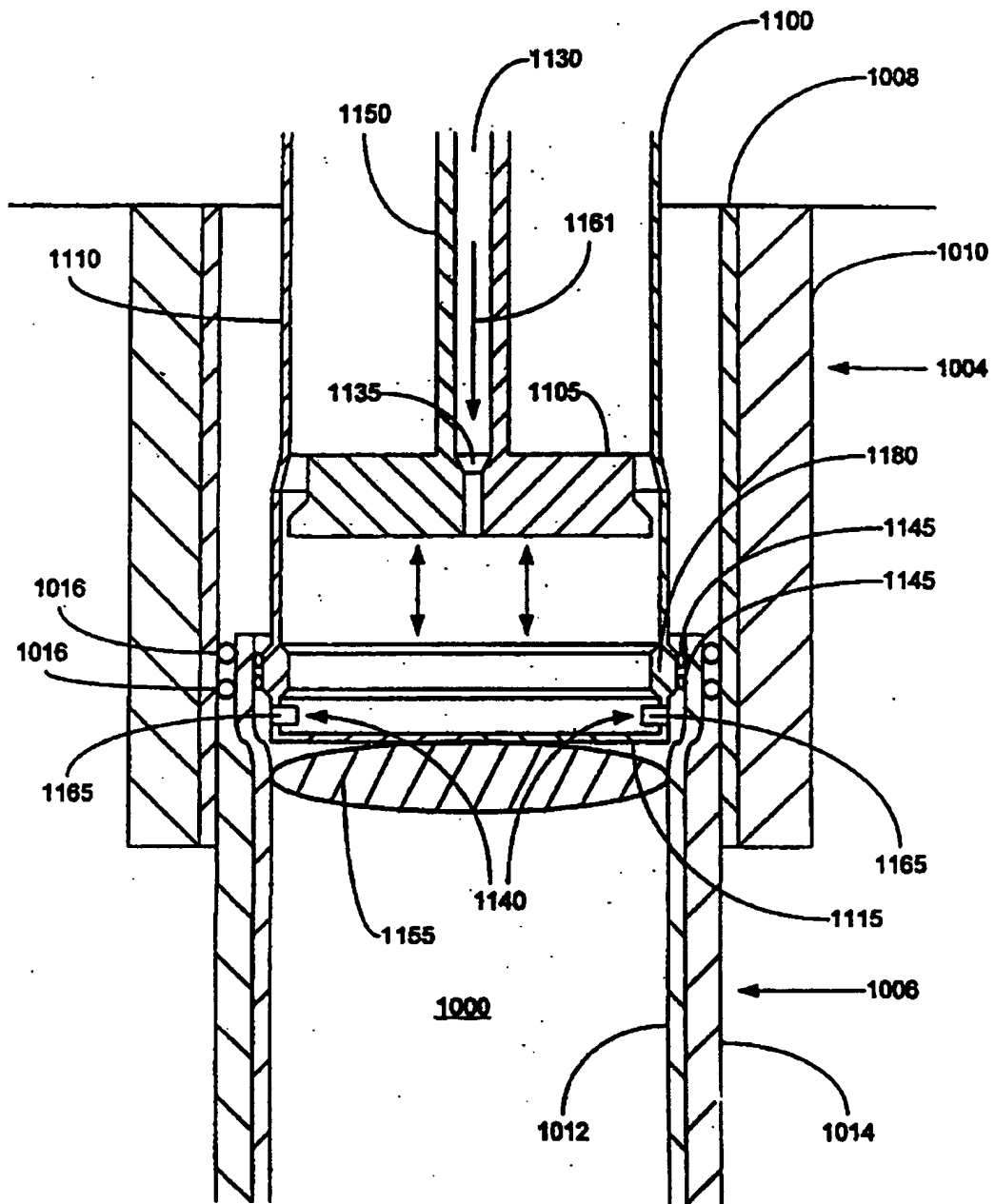


FIGURE 10e

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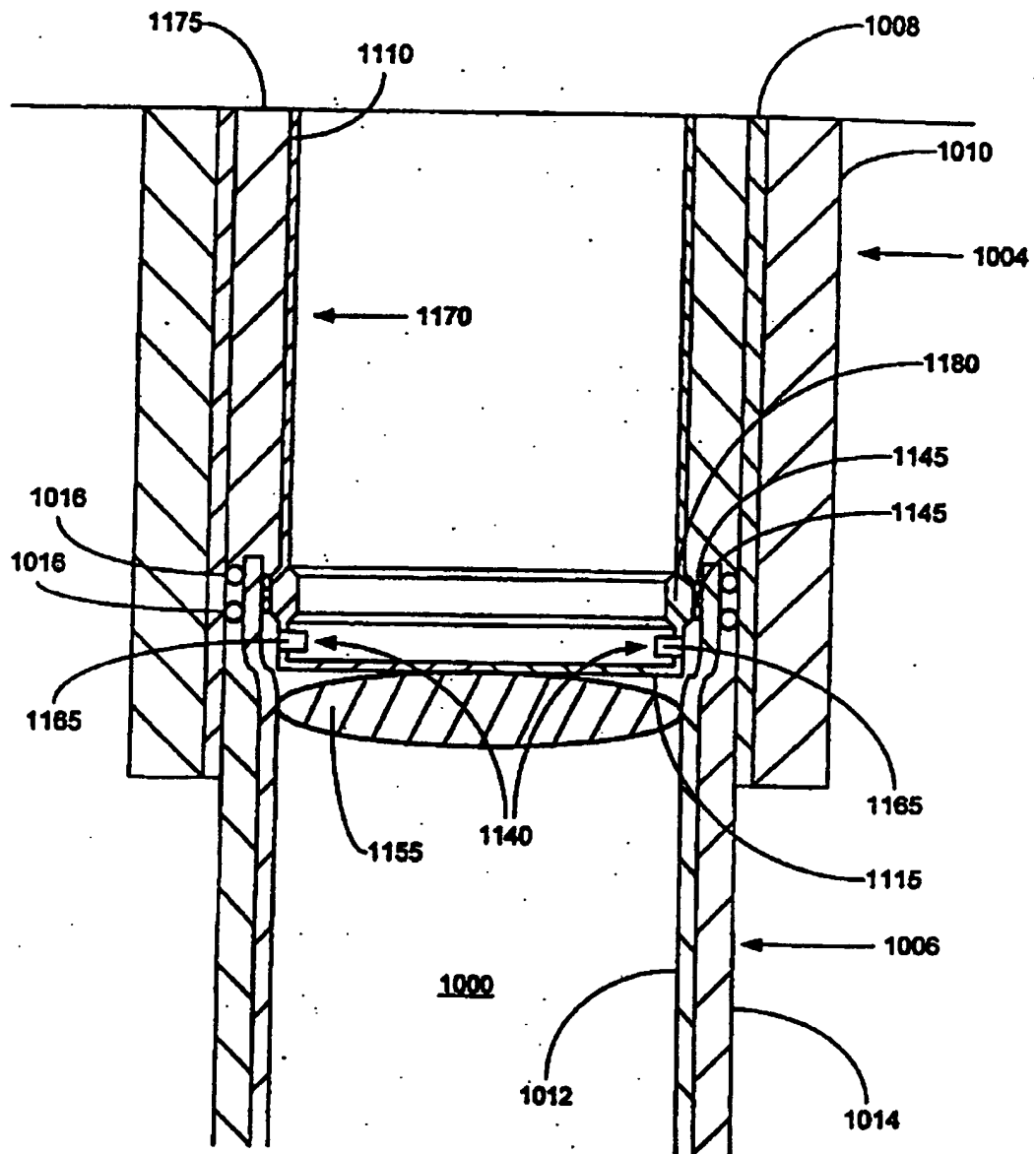


FIGURE 10f

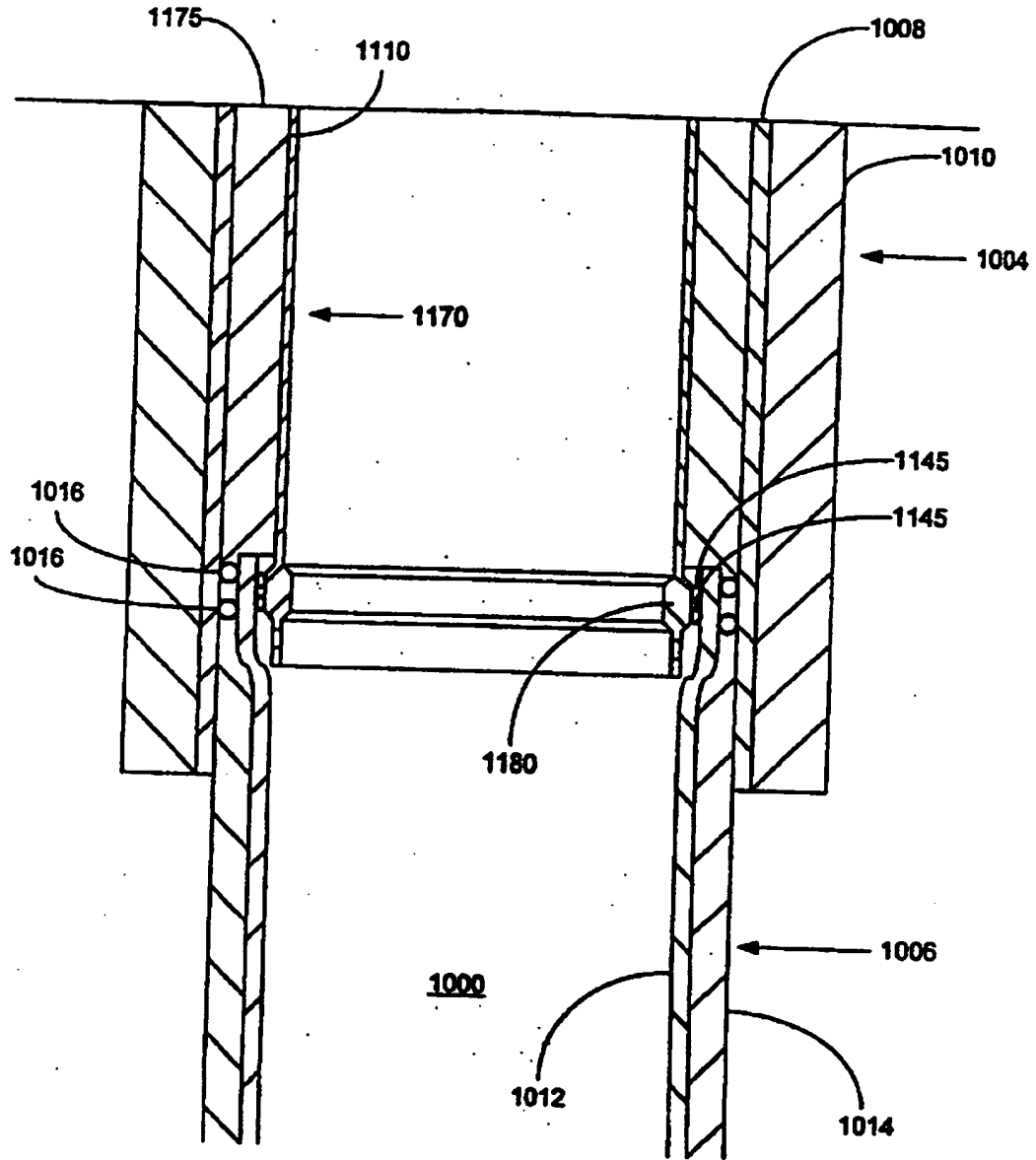


FIGURE 10g

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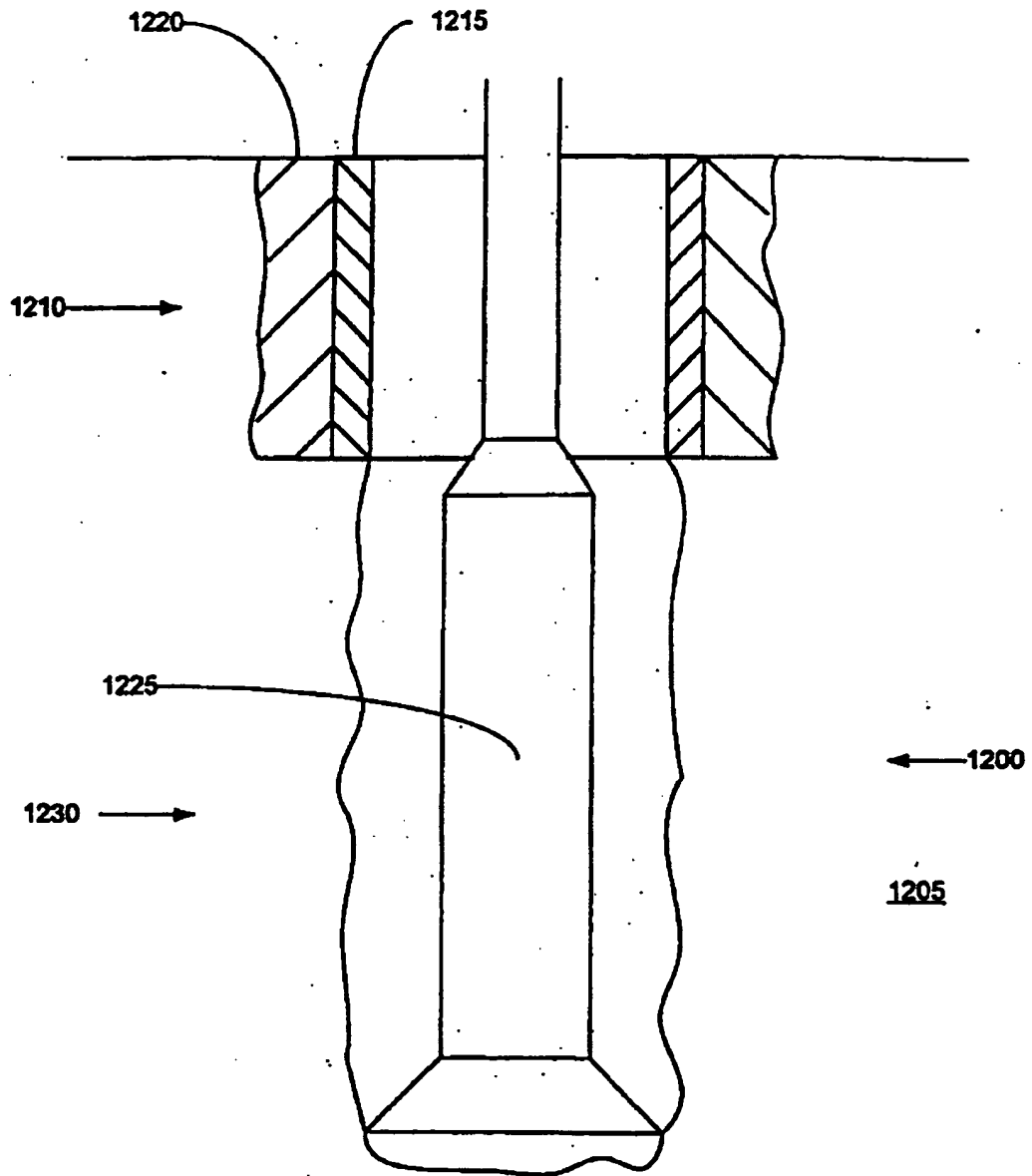


FIGURE 11a

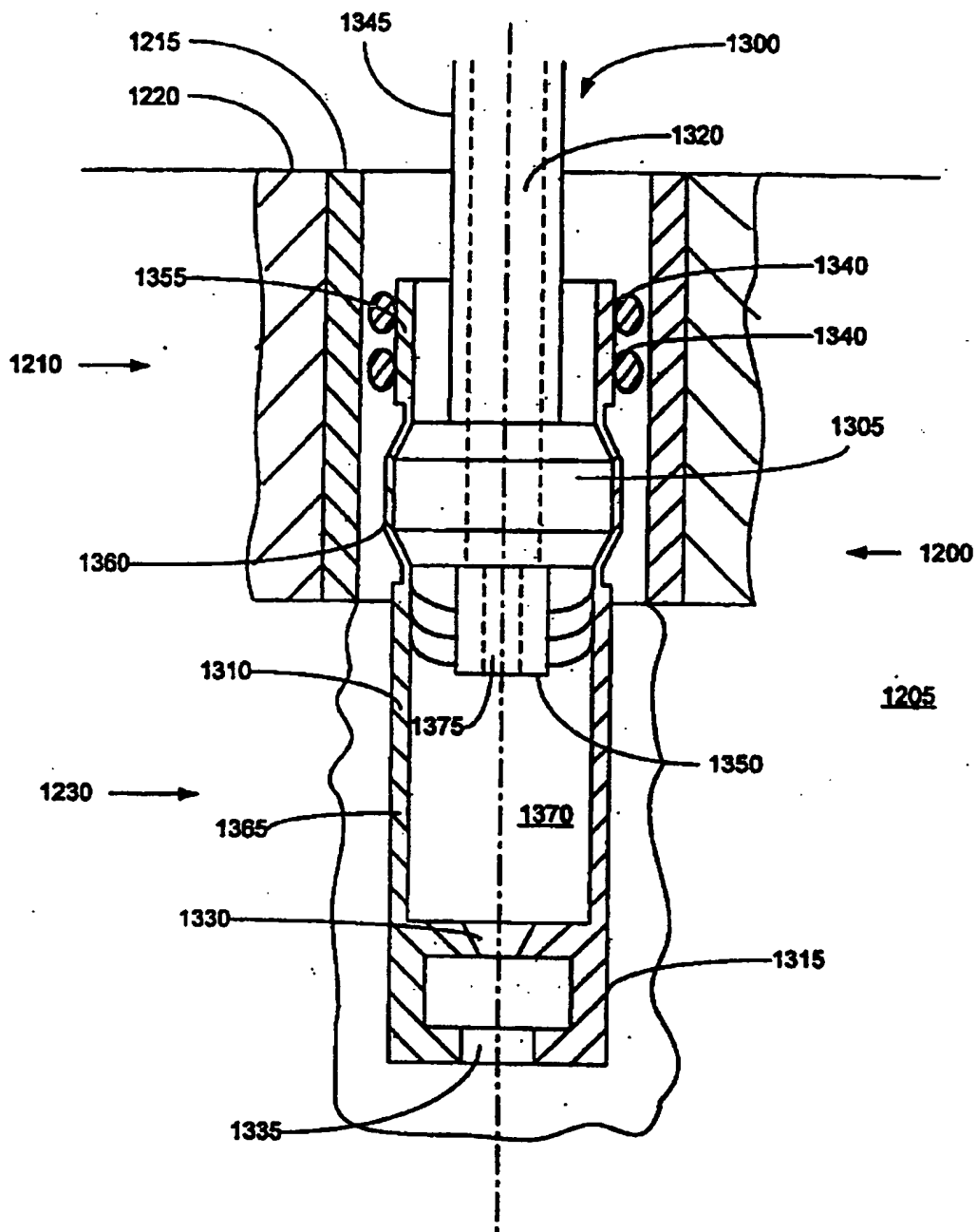


FIGURE 11b

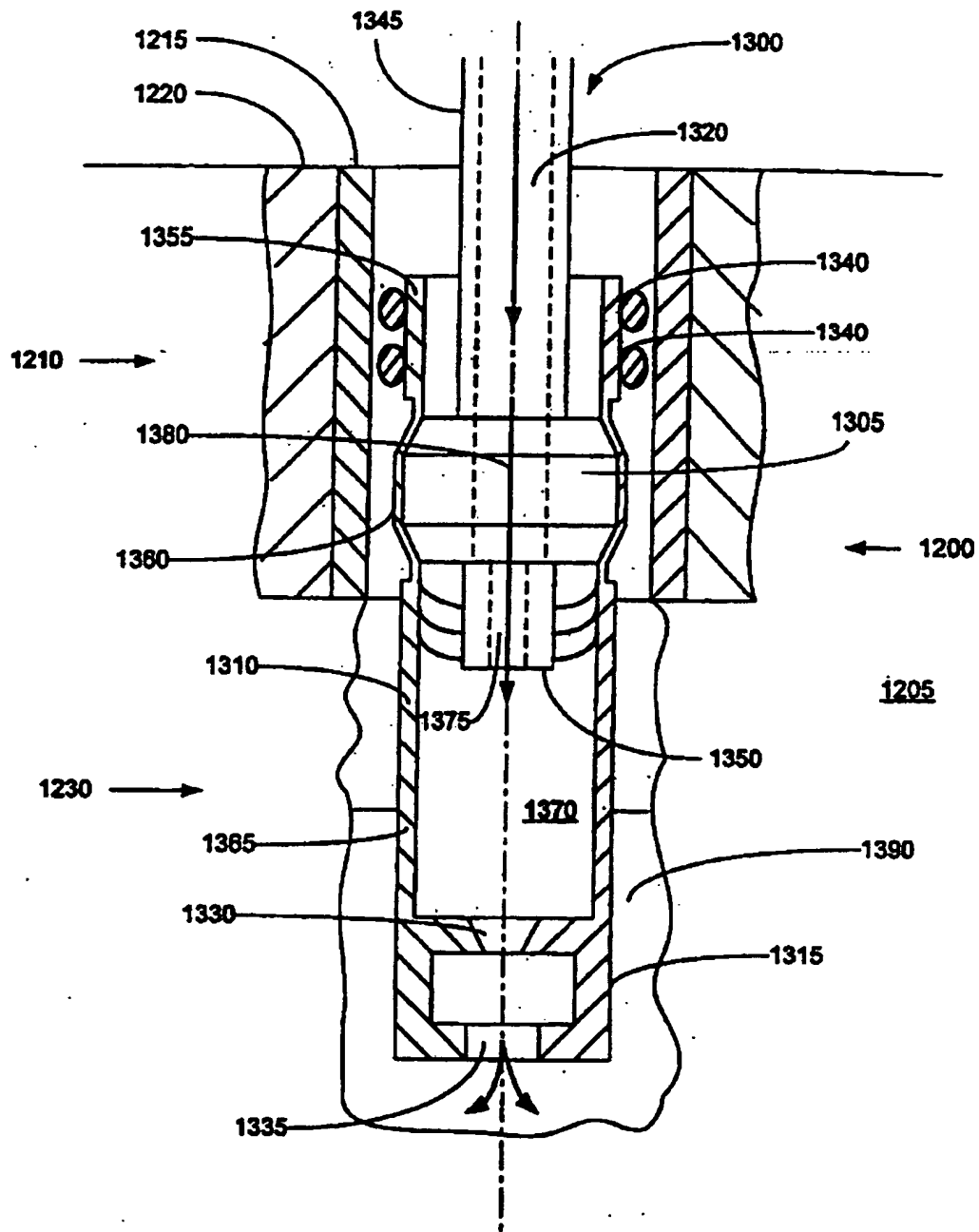


FIGURE 11c

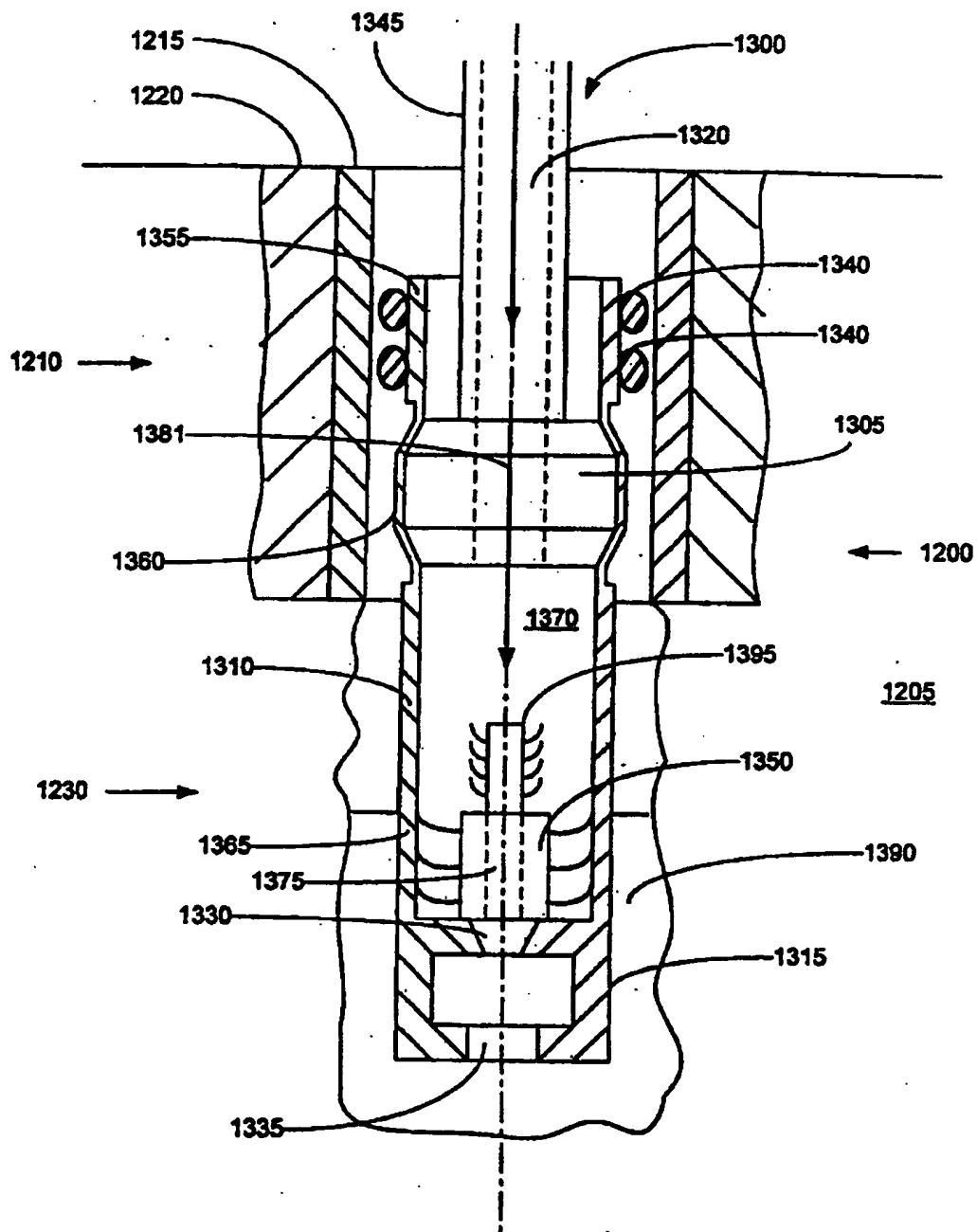


FIGURE 11e

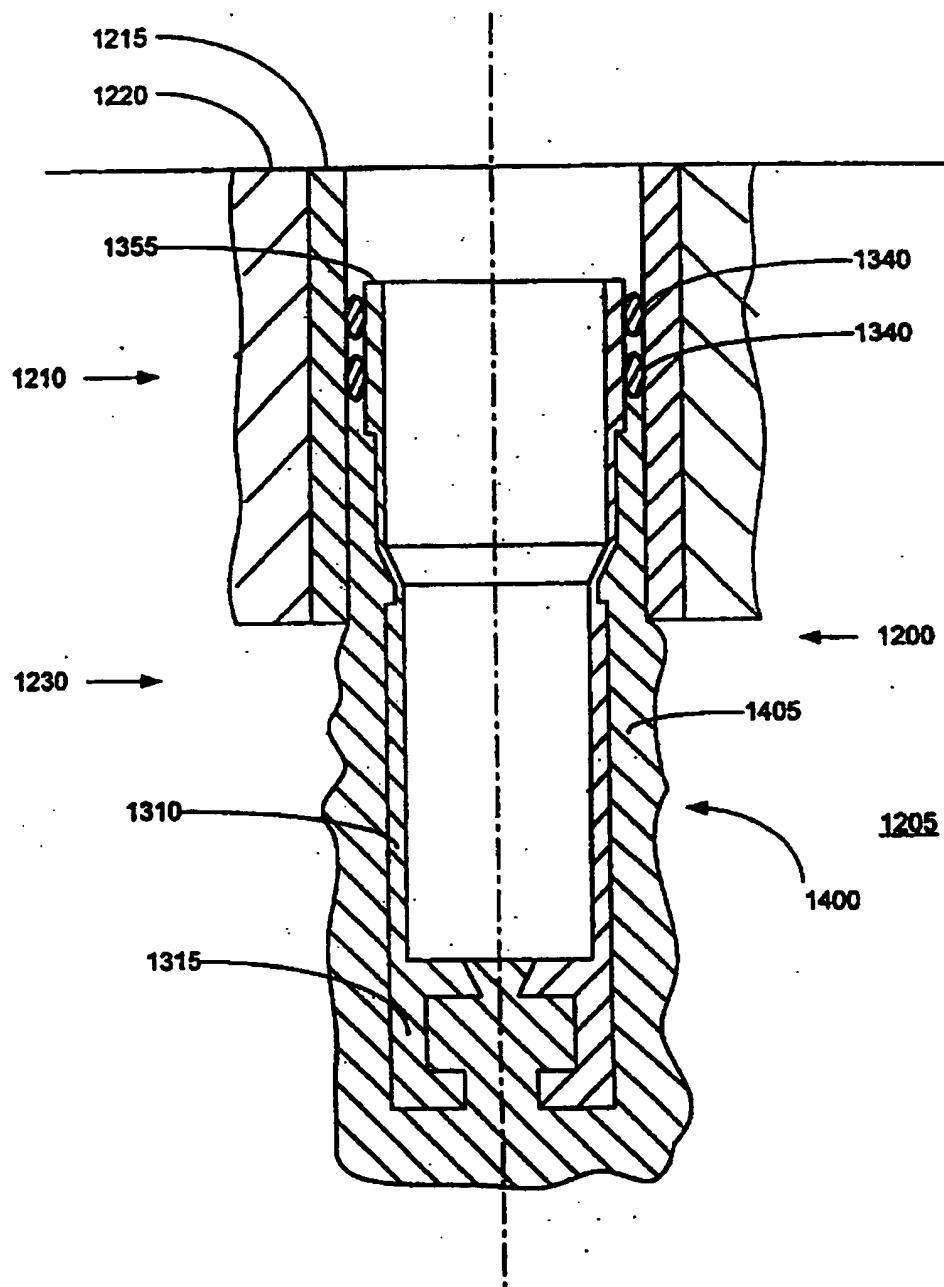


FIGURE 11f

WELLBORE CASING

Cross Reference To Related Applications

This application claims the benefit of the filing date of U.S. Provisional Patent Application Serial Number 60/111,293, attorney docket number 25791.3, filed on 12/7/1998, the disclosure of which is incorporated herein by reference.

Background of the Invention

This invention relates generally to wellbore casings, and in particular to wellbore casings that are formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are
5 installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure
10 the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole
15 diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters
20 drilled in the course of the well, and the large volume of cuttings drilled and removed.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming new sections of casing in a wellbore.

25

Summary of the Invention

According to one aspect of the present invention, a method of forming a wellbore casing is provided that includes installing a tubular liner and a mandrel

in the borehole, injecting fluidic material into the borehole, and radially expanding the liner in the borehole by extruding the liner off of the mandrel.

According to another aspect of the present invention, a method of forming a wellbore casing is provided that includes drilling out a new section of the
5 borehole adjacent to the already existing casing. A tubular liner and a mandrel are then placed into the new section of the borehole with the tubular liner overlapping an already existing casing. A hardenable fluidic sealing material is injected into an annular region between the tubular liner and the new section of the borehole. The annular region between the tubular liner and the new section of the borehole
10 is then fluidically isolated from an interior region of the tubular liner below the mandrel. A non hardenable fluidic material is then injected into the interior region of the tubular liner below the mandrel. The tubular liner is extruded off of the mandrel. The overlap between the tubular liner and the already existing casing is sealed. The tubular liner is supported by overlap with the already
15 existing casing. The mandrel is removed from the borehole. The integrity of the seal of the overlap between the tubular liner and the already existing casing is tested. At least a portion of the second quantity of the hardenable fluidic sealing material is removed from the interior of the tubular liner. The remaining portions of the fluidic hardenable fluidic sealing material are cured. At least a portion of
20 cured fluidic hardenable sealing material within the tubular liner is removed.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, a mandrel, a tubular member, and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member and includes a second
25 fluid passage. The tubular member is coupled to the mandrel. The shoe is coupled to the tubular liner and includes a third fluid passage. The first, second and third fluid passages are operably coupled.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, an
30 expandable mandrel, a tubular member, a shoe, and at least one sealing member. The support member includes a first fluid passage, a second fluid passage, and a flow control valve coupled to the first and second fluid passages. The expandable

mandrel is coupled to the support member and includes a third fluid passage. The tubular member is coupled to the mandrel and includes one or more sealing elements. The shoe is coupled to the tubular member and includes a fourth fluid passage. The at least one sealing member is adapted to prevent the entry of
5 foreign material into an interior region of the tubular member.

According to another aspect of the present invention, a method of joining a second tubular member to a first tubular member, the first tubular member having an inner diameter greater than an outer diameter of the second tubular member, is provided that includes positioning a mandrel within an interior region
10 of the second tubular member. A portion of an interior region of the second tubular member is pressurized and the second tubular member is extruded off of the mandrel into engagement with the first tubular member.

According to another aspect of the present invention, a tubular liner is provided that includes an annular member having one or more sealing members
15 at an end portion of the annular member, and one or more pressure relief passages at an end portion of the annular member.

According to another aspect of the present invention, a wellbore casing is provided that includes a tubular liner and an annular body of a cured fluidic sealing material. The tubular liner is formed by the process of extruding the
20 tubular liner off of a mandrel.

According to another aspect of the present invention, a tie-back liner for lining an existing wellbore casing is provided that includes a tubular liner and an annular body of cured fluidic sealing material. The tubular liner is formed by the process of extruding the tubular liner off of a mandrel. The annular body of a
25 cured fluidic sealing material is coupled to the tubular liner.

According to another aspect of the present invention, an apparatus for expanding a tubular member is provided that includes a support member, a mandrel, a tubular member and a shoe. The support member includes a first fluid passage. The mandrel is coupled to the support member. The mandrel includes
30 a second fluid passage operably coupled to the first fluid passage, an interior portion, and an exterior portion. The interior portion of the mandrel is drillable. The tubular member is coupled to the mandrel. The shoe is coupled to the tubular

member. The shoe includes a third fluid passage operably coupled to the second fluid passage, an interior portion, and an exterior portion. The interior portion of the shoe is drillable.

Brief Description of the Drawings

5 FIG. 1 is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

FIG. 2 is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for creating a casing within the new section of the well borehole.

10 FIG. 3 is a fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 3a is another fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of
15 the well borehole.

FIG. 4 is a fragmentary cross-sectional view illustrating the injection of a second quantity of a hardenable fluidic sealing material into the new section of the well borehole.

FIG. 5 is a fragmentary cross-sectional view illustrating the drilling out of
20 a portion of the cured hardenable fluidic sealing material from the new section of the well borehole.

FIG. 6 is a cross-sectional view of an embodiment of the overlapping joint between adjacent tubular members.

FIG. 7 is a fragmentary cross-sectional view of a preferred embodiment of
25 the apparatus for creating a casing within a well borehole.

FIG. 8 is a fragmentary cross-sectional illustration of the placement of an expanded tubular member within another tubular member.

FIG. 9 is a cross-sectional illustration of a preferred embodiment of an apparatus for forming a casing including a drillable mandrel and shoe.

30 FIG. 9a is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9b is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 9c is another cross-sectional illustration of the apparatus of FIG. 9.

FIG. 10a is a cross-sectional illustration of a wellbore including a pair of adjacent overlapping casings.

FIG. 10b is a cross-sectional illustration of an apparatus and method for creating a tie-back liner using an expandible tubular member.

5 FIG. 10c is a cross-sectional illustration of the pumping of a fluidic sealing material into the annular region between the tubular member and the existing casing.

FIG. 10d is a cross-sectional illustration of the pressurizing of the interior of the tubular member below the mandrel.

10 FIG. 10e is a cross-sectional illustration of the extrusion of the tubular member off of the mandrel.

FIG. 10f is a cross-sectional illustration of the tie-back liner before drilling out the shoe and packer.

15 FIG. 10g is a cross-sectional illustration of the completed tie-back liner created using an expandible tubular member.

FIG. 11a is a fragmentary cross-sectional view illustrating the drilling of a new section of a well borehole.

20 FIG. 11b is a fragmentary cross-sectional view illustrating the placement of an embodiment of an apparatus for hanging a tubular liner within the new section of the well borehole.

FIG. 11c is a fragmentary cross-sectional view illustrating the injection of a first quantity of a hardenable fluidic sealing material into the new section of the well borehole.

25 FIG. 11d is a fragmentary cross-sectional view illustrating the introduction of a wiper dart into the new section of the well borehole.

FIG. 11e is a fragmentary cross-sectional view illustrating the injection of a second quantity of a hardenable fluidic sealing material into the new section of the well borehole.

30 FIG. 11f is a fragmentary cross-sectional view illustrating the completion of the tubular liner.

Detailed Description of the Illustrative Embodiments

An apparatus and method for forming a wellbore casing within a subterranean formation is provided. The apparatus and method permits a wellbore casing to be formed in a subterranean formation by placing a tubular member and a mandrel in a new section of a wellbore, and then extruding the tubular member off of the mandrel by pressurizing an interior portion of the tubular member. The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and or gas passage. The apparatus and method further permits a new tubular member to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member. The apparatus and method further minimizes the reduction in the hole size of the wellbore casing necessitated by the addition of new sections of wellbore casing.

An apparatus and method for forming a tie-back liner using an expandable tubular member is also provided. The apparatus and method permits a tie-back liner to be created by extruding a tubular member off of a mandrel by pressurizing and interior portion of the tubular member. In this manner, a tie-back liner is produced. The apparatus and method further permits adjacent tubular members in the wellbore to be joined using an overlapping joint that prevents fluid and/or gas passage. The apparatus and method further permits a new tubular member to be supported by an existing tubular member by expanding the new tubular member into engagement with the existing tubular member.

An apparatus and method for expanding a tubular member is also provided that includes an expandable tubular member, mandrel and a shoe. In a preferred embodiment, the interior portions of the apparatus is composed of materials that permit the interior portions to be removed using a conventional drilling apparatus. In this manner, in the event of a malfunction in a downhole region, the apparatus may be easily removed.

An apparatus and method for hanging an expandable tubular liner in a wellbore is also provided. The apparatus and method permit a tubular liner to be attached to an existing section of casing. The apparatus and method further have application to the joining of tubular members in general.

Referring initially to Figs. 1-5, an embodiment of an apparatus and method for forming a wellbore casing within a subterranean formation will now be described. As illustrated in Fig. 1, a wellbore 100 is positioned in a subterranean formation 105. The wellbore 100 includes an existing cased section 110 having a 5 tubular casing 115 and an annular outer layer of cement 120.

In order to extend the wellbore 100 into the subterranean formation 105, a drill string 125 is used in a well known manner to drill out material from the subterranean formation 105 to form a new section 130.

As illustrated in Fig. 2, an apparatus 200 for forming a wellbore casing in 10 a subterranean formation is then positioned in the new section 130 of the wellbore 100. The apparatus 200 preferably includes an expandable mandrel or pig 205, a tubular member 210, a shoe 215, a lower cup seal 220, an upper cup seal 225, a fluid passage 230, a fluid passage 235, a fluid passage 240, seals 245, and a support member 250.

15 The expandable mandrel 205 is coupled to and supported by the support member 250. The expandable mandrel 205 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 205 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred 20 embodiment, the expandable mandrel 205 comprises a hydraulic expansion tool as disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The tubular member 210 is supported by the expandable mandrel 205. The 25 tubular member 210 is expanded in the radial direction and extruded off of the expandable mandrel 205. The tubular member 210 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, or plastic tubing/casing. In a preferred embodiment, the tubular member 210 is 30 fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 210 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. In a preferred

embodiment, the inner and outer diameters of the tubular member 210 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 210 preferably comprises a solid member.

5 In a preferred embodiment, the end portion 260 of the tubular member 210 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 205 when it completes the extrusion of tubular member 210. In a preferred embodiment, the length of the tubular member 210 is limited to minimize the possibility of buckling. For typical tubular member 210 materials, the length of
10 the tubular member 210 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 215 is coupled to the expandable mandrel 205 and the tubular member 210. The shoe 215 includes fluid passage 240. The shoe 215 may comprise any number of conventional commercially available shoes such as, for
15 example, Super Seal II float shoe, Super Seal II Down-Jet float shoe or a guide shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 215 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in
20 accordance with the teachings of the present disclosure, in order to optimally guide the tubular member 210 in the wellbore, optimally provide an adequate seal between the interior and exterior diameters of the overlapping joint between the tubular members, and to optimally allow the complete drill out of the shoe and plug after the completion of the cementing and expansion operations.

25 In a preferred embodiment, the shoe 215 includes one or more through and side outlet ports in fluidic communication with the fluid passage 240. In this manner, the shoe 215 optimally injects hardenable fluidic sealing material into the region outside the shoe 215 and tubular member 210. In a preferred embodiment, the shoe 215 includes the fluid passage 240 having an inlet geometry that can
30 receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be optimally sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

The lower cup seal 220 is coupled to and supported by the support member 250. The lower cup seal 220 prevents foreign materials from entering the interior region of the tubular member 210 adjacent to the expandable mandrel 205. The lower cup seal 220 may comprise any number of conventional commercially available cup seals such as, for example, TP cups, or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 220 comprises a SIP cup seal, available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign material and contain a body of lubricant.

10 The upper cup seal 225 is coupled to and supported by the support member 250. The upper cup seal 225 prevents foreign materials from entering the interior region of the tubular member 210. The upper cup seal 225 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present
15 disclosure. In a preferred embodiment, the upper cup seal 225 comprises a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant.

The fluid passage 230 permits fluidic materials to be transported to and from the interior region of the tubular member 210 below the expandable mandrel
20 205. The fluid passage 230 is coupled to and positioned within the support member 250 and the expandable mandrel 205. The fluid passage 230 preferably extends from a position adjacent to the surface to the bottom of the expandable mandrel 205. The fluid passage 230 is preferably positioned along a centerline of the apparatus 200.

25 The fluid passage 230 is preferably selected, in the casing running mode of operation, to transport materials such as drilling mud or formation fluids at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to minimize drag on the tubular member being run and to minimize surge pressures exerted on the wellbore which could cause a loss of wellbore fluids
30 and lead to hole collapse.

The fluid passage 235 permits fluidic materials to be released from the fluid passage 230. In this manner, during placement of the apparatus 200 within the

new section 130 of the wellbore 100, fluidic materials 255 forced up the fluid passage 230 can be released into the wellbore 100 above the tubular member 210 thereby minimizing surge pressures on the wellbore section 130. The fluid passage 235 is coupled to and positioned within the support member 250. The fluid
5 passage is further fluidically coupled to the fluid passage 230.

The fluid passage 235 preferably includes a control valve for controllably opening and closing the fluid passage 235. In a preferred embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The fluid passage 235 is preferably positioned substantially orthogonal to the centerline
10 of the apparatus 200.

The fluid passage 235 is preferably selected to convey fluidic materials at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to reduce the drag on the apparatus 200 during insertion into the new section 130 of the wellbore 100 and to minimize surge pressures on the
15 new wellbore section 130.

The fluid passage 240 permits fluidic materials to be transported to and from the region exterior to the tubular member 210 and shoe 215. The fluid passage 240 is coupled to and positioned within the shoe 215 in fluidic communication with the interior region of the tubular member 210 below the
20 expandable mandrel 205. The fluid passage 240 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in fluid passage 240 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 210 below the expandable mandrel 205 can be fluidically isolated from the region exterior to the tubular member 210. This permits
25 the interior region of the tubular member 210 below the expandable mandrel 205 to be pressurized. The fluid passage 240 is preferably positioned substantially along the centerline of the apparatus 200.

The fluid passage 240 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0
30 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill the annular region between the tubular member 210 and the new section 130 of the wellbore 100 with fluidic materials. In a preferred embodiment, the fluid passage 240

includes an inlet geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

The seals 245 are coupled to and supported by an end portion 260 of the tubular member 210. The seals 245 are further positioned on an outer surface 265 of the end portion 260 of the tubular member 210. The seals 245 permit the overlapping joint between the end portion 270 of the casing 115 and the portion 260 of the tubular member 210 to be fluidically sealed. The seals 245 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the seals 245 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 260 of the tubular member 210 and the end 270 of the existing casing 115.

In a preferred embodiment, the seals 245 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 210 from the existing casing 115. In a preferred embodiment, the frictional force optimally provided by the seals 245 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 210.

The support member 250 is coupled to the expandable mandrel 205, tubular member 210, shoe 215, and seals 220 and 225. The support member 250 preferably comprises an annular member having sufficient strength to carry the apparatus 200 into the new section 130 of the wellbore 100. In a preferred embodiment, the support member 250 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 200.

In a preferred embodiment, a quantity of lubricant 275 is provided in the annular region above the expandable mandrel 205 within the interior of the tubular member 210. In this manner, the extrusion of the tubular member 210 off of the expandable mandrel 205 is facilitated. The lubricant 275 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). In a preferred embodiment, the lubricant 275 comprises Climax 1500

Antisize (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

In a preferred embodiment, the support member 250 is thoroughly cleaned
5 prior to assembly to the remaining portions of the apparatus 200. In this manner, the introduction of foreign material into the apparatus 200 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 200.

In a preferred embodiment, before or after positioning the apparatus 200
10 within the new section 130 of the wellbore 100, a couple of wellbore volumes are circulated in order to ensure that no foreign materials are located within the wellbore 100 that might clog up the various flow passages and valves of the apparatus 200 and to ensure that no foreign material interferes with the expansion process.

15 As illustrated in Fig. 3, the fluid passage 235 is then closed and a hardenable fluidic sealing material 305 is then pumped from a surface location into the fluid passage 230. The material 305 then passes from the fluid passage 230 into the interior region 310 of the tubular member 210 below the expandable mandrel 205. The material 305 then passes from the interior region 310 into the fluid passage
20 240. The material 305 then exits the apparatus 200 and fills the annular region 315 between the exterior of the tubular member 210 and the interior wall of the new section 130 of the wellbore 100. Continued pumping of the material 305 causes the material 305 to fill up at least a portion of the annular region 315.

The material 305 is preferably pumped into the annular region 315 at
25 pressures and flow rates ranging, for example, from about 0 to 5000 psi and 0 to 1,500 gallons/min, respectively. The optimum flow rate and operating pressures vary as a function of the casing and wellbore sizes, wellbore section length, available pumping equipment, and fluid properties of the fluidic material being pumped. The optimum flow rate and operating pressure are preferably determined
30 using conventional empirical methods.

The hardenable fluidic sealing material 305 may comprise any number of conventional commercially available hardenable fluidic sealing materials such as,

for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material 305 comprises a blended cement prepared specifically for the particular well section being drilled from Halliburton Energy Services in Dallas, TX in order to provide optimal support for tubular member 210 5 while also maintaining optimum flow characteristics so as to minimize difficulties during the displacement of cement in the annular region 315. The optimum blend of the blended cement is preferably determined using conventional empirical methods.

The annular region 315 preferably is filled with the material 305 in 10 sufficient quantities to ensure that, upon radial expansion of the tubular member 210, the annular region 315 of the new section 130 of the wellbore 100 will be filled with material 305.

In a particularly preferred embodiment, as illustrated in Fig. 3a, the wall thickness and/or the outer diameter of the tubular member 210 is reduced in the 15 region adjacent to the mandrel 205 in order optimally permit placement of the apparatus 200 in positions in the wellbore with tight clearances. Furthermore, in this manner, the initiation of the radial expansion of the tubular member 210 during the extrusion process is optimally facilitated.

As illustrated in Fig. 4, once the annular region 315 has been adequately 20 filled with material 305, a plug 405, or other similar device, is introduced into the fluid passage 240 thereby fluidically isolating the interior region 310 from the annular region 315. In a preferred embodiment, a non-hardenable fluidic material 306 is then pumped into the interior region 310 causing the interior region to pressurize. In this manner, the interior of the expanded tubular member 210 will 25 not contain significant amounts of cured material 305. This reduces and simplifies the cost of the entire process. Alternatively, the material 305 may be used during this phase of the process.

Once the interior region 310 becomes sufficiently pressurized, the tubular member 210 is extruded off of the expandable mandrel 205. During the extrusion 30 process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210. In a preferred embodiment, during the extrusion process, the mandrel 205 is raised at approximately the same rate as the tubular

member 210 is expanded in order to keep the tubular member 210 stationary relative to the new wellbore section 130. In an alternative preferred embodiment, the extrusion process is commenced with the tubular member 210 positioned above the bottom of the new wellbore section 130, keeping the mandrel 205 stationary, 5 and allowing the tubular member 210 to extrude off of the mandrel 205 and fall down the new wellbore section 130 under the force of gravity.

The plug 405 is preferably placed into the fluid passage 240 by introducing the plug 405 into the fluid passage 230 at a surface location in a conventional manner. The plug 405 preferably acts to fluidically isolate the hardenable fluidic 10 sealing material 305 from the non hardenable fluidic material 306.

The plug 405 may comprise any number of conventional commercially available devices from plugging a fluid passage such as, for example, Multiple Stage Cementer (MSC) latch-down plug, Omega latch-down plug or three-wiper latch-down plug modified in accordance with the teachings of the present disclosure. In 15 a preferred embodiment, the plug 405 comprises a MSC latch-down plug available from Halliburton Energy Services in Dallas, TX.

After placement of the plug 405 in the fluid passage 240, a non hardenable fluidic material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging, for example, from approximately 400 to 10,000 psi and 30 20 to 4,000 gallons/min. In this manner, the amount of hardenable fluidic sealing material within the interior 310 of the tubular member 210 is minimized. In a preferred embodiment, after placement of the plug 405 in the fluid passage 240, the non hardenable material 306 is preferably pumped into the interior region 310 at pressures and flow rates ranging from approximately 500 to 9,000 psi and 40 to 25 3,000 gallons/min in order to maximize the extrusion speed.

In a preferred embodiment, the apparatus 200 is adapted to minimize tensile, burst, and friction effects upon the tubular member 210 during the expansion process. These effects will be depend upon the geometry of the expansion mandrel 205, the material composition of the tubular member 210 and 30 expansion mandrel 205, the inner diameter of the tubular member 210, the wall thickness of the tubular member 210, the type of lubricant, and the yield strength of the tubular member 210. In general, the thicker the wall thickness, the smaller

the inner diameter, and the greater the yield strength of the tubular member 210, then the greater the operating pressures required to extrude the tubular member 210 off of the mandrel 205.

For typical tubular members 210, the extrusion of the tubular member 210 off of the expandable mandrel will begin when the pressure of the interior region 310 reaches, for example, approximately 500 to 9,000 psi.

During the extrusion process, the expandable mandrel 205 may be raised out of the expanded portion of the tubular member 210 at rates ranging, for example, from about 0 to 5 ft/sec. In a preferred embodiment, during the extrusion process, the expandable mandrel 205 is raised out of the expanded portion of the tubular member 210 at rates ranging from about 0 to 2 ft/sec in order to minimize the time required for the expansion process while also permitting easy control of the expansion process.

When the end portion 260 of the tubular member 210 is extruded off of the expandable mandrel 205, the outer surface 265 of the end portion 260 of the tubular member 210 will preferably contact the interior surface 410 of the end portion 270 of the casing 115 to form an fluid tight overlapping joint. The contact pressure of the overlapping joint may range, for example, from approximately 50 to 20,000 psi. In a preferred embodiment, the contact pressure of the overlapping joint ranges from approximately 400 to 10,000 psi in order to provide optimum pressure to activate the annular sealing members 245 and optimally provide resistance to axial motion to accommodate typical tensile and compressive loads.

The overlapping joint between the section 410 of the existing casing 115 and the section 265 of the expanded tubular member 210 preferably provides a gaseous and fluidic seal. In a particularly preferred embodiment, the sealing members 245 optimally provide a fluidic and gaseous seal in the overlapping joint.

In a preferred embodiment, the operating pressure and flow rate of the non hardenable fluidic material 306 is controllably ramped down when the expandable mandrel 205 reaches the end portion 260 of the tubular member 210. In this manner, the sudden release of pressure caused by the complete extrusion of the tubular member 210 off of the expandable mandrel 205 can be minimized. In a

preferred embodiment, the operating pressure is reduced in a substantially linear fashion from 100% to about 10% during the end of the extrusion process beginning when the mandrel 205 is within about 5 feet from completion of the extrusion process.

5 Alternatively, or in combination, a shock absorber is provided in the support member 250 in order to absorb the shock caused by the sudden release of pressure. The shock absorber may comprise, for example, any conventional commercially available shock absorber adapted for use in wellbore operations.

10 Alternatively, or in combination, a mandrel catching structure is provided in the end portion 260 of the tubular member 210 in order to catch or at least decelerate the mandrel 205.

Once the extrusion process is completed, the expandable mandrel 205 is removed from the wellbore 100. In a preferred embodiment, either before or after the removal of the expandable mandrel 205, the integrity of the fluidic seal of the 15 overlapping joint between the upper portion 260 of the tubular member 210 and the lower portion 270 of the casing 115 is tested using conventional methods.

If the fluidic seal of the overlapping joint between the upper portion 260 of the tubular member 210 and the lower portion 270 of the casing 115 is satisfactory, then any uncured portion of the material 305 within the expanded tubular member 20 210 is then removed in a conventional manner such as, for example, circulating the uncured material out of the interior of the expanded tubular member 210. The mandrel 205 is then pulled out of the wellbore section 130 and a drill bit or mill is used in combination with a conventional drilling assembly 505 to drill out any hardened material 305 within the tubular member 210. The material 305 within 25 the annular region 315 is then allowed to cure.

As illustrated in Fig. 5, preferably any remaining cured material 305 within the interior of the expanded tubular member 210 is then removed in a conventional manner using a conventional drill string 505. The resulting new section of casing 510 includes the expanded tubular member 210 and an outer 30 annular layer 515 of cured material 305. The bottom portion of the apparatus 200 comprising the shoe 215 and dart 405 may then be removed by drilling out the shoe 215 and dart 405 using conventional drilling methods.

In a preferred embodiment, as illustrated in Fig. 6, the upper portion 260 of the tubular member 210 includes one or more sealing members 605 and one or more pressure relief holes 610. In this manner, the overlapping joint between the lower portion 270 of the casing 115 and the upper portion 260 of the tubular member 210 is pressure-tight and the pressure on the interior and exterior surfaces of the tubular member 210 is equalized during the extrusion process.

In a preferred embodiment, the sealing members 605 are seated within recesses 615 formed in the outer surface 265 of the upper portion 260 of the tubular member 210. In an alternative preferred embodiment, the sealing members 605 are bonded or molded onto the outer surface 265 of the upper portion 260 of the tubular member 210. The pressure relief holes 610 are preferably positioned in the last few feet of the tubular member 210. The pressure relief holes reduce the operating pressures required to expand the upper portion 260 of the tubular member 210. This reduction in required operating pressure in turn reduces the velocity of the mandrel 205 upon the completion of the extrusion process. This reduction in velocity in turn minimizes the mechanical shock to the entire apparatus 200 upon the completion of the extrusion process.

Referring now to Fig. 7, a particularly preferred embodiment of an apparatus 700 for forming a casing within a wellbore preferably includes an expandable mandrel or pig 705, an expandable mandrel or pig container 710, a tubular member 715, a float shoe 720, a lower cup seal 725, an upper cup seal 730, a fluid passage 735, a fluid passage 740, a support member 745, a body of lubricant 750, an overshot connection 755, another support member 760, and a stabilizer 765.

The expandable mandrel 705 is coupled to and supported by the support member 745. The expandable mandrel 705 is further coupled to the expandable mandrel container 710. The expandable mandrel 705 is preferably adapted to controllably expand in a radial direction. The expandable mandrel 705 may comprise any number of conventional commercially available expandable mandrels modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the expandable mandrel 705 comprises a hydraulic expansion tool substantially as disclosed in U.S. Pat. No. 5,948,095, the contents of which are

incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The expandable mandrel container 710 is coupled to and supported by the support member 745. The expandable mandrel container 710 is further coupled
5 to the expandable mandrel 705. The expandable mandrel container 710 may be constructed from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods, stainless steel, titanium or high strength steels. In a preferred embodiment, the expandable mandrel container 710 is fabricated from material having a greater strength than the
10 material from which the tubular member 715 is fabricated. In this manner, the container 710 can be fabricated from a tubular material having a thinner wall thickness than the tubular member 210. This permits the container 710 to pass through tight clearances thereby facilitating its placement within the wellbore.

In a preferred embodiment, once the expansion process begins, and the
15 thicker, lower strength material of the tubular member 715 is expanded, the outside diameter of the tubular member 715 is greater than the outside diameter of the container 710.

The tubular member 715 is coupled to and supported by the expandable mandrel 705. The tubular member 715 is preferably expanded in the radial
20 direction and extruded off of the expandable mandrel 705 substantially as described above with reference to Figs. 1-6. The tubular member 715 may be fabricated from any number of materials such as, for example, Oilfield Country Tubular Goods (OCTG), automotive grade steel or plastics. In a preferred embodiment, the tubular member 715 is fabricated from OCTG.

25 In a preferred embodiment, the tubular member 715 has a substantially annular cross-section. In a particularly preferred embodiment, the tubular member 715 has a substantially circular annular cross-section.

The tubular member 715 preferably includes an upper section 805, an intermediate section 810, and a lower section 815. The upper section 805 of the
30 tubular member 715 preferably is defined by the region beginning in the vicinity of the mandrel container 710 and ending with the top section 820 of the tubular member 715. The intermediate section 810 of the tubular member 715 is

preferably defined by the region beginning in the vicinity of the top of the mandrel container 710 and ending with the region in the vicinity of the mandrel 705. The lower section of the tubular member 715 is preferably defined by the region beginning in the vicinity of the mandrel 705 and ending at the bottom 825 of the tubular member 715.

In a preferred embodiment, the wall thickness of the upper section 805 of the tubular member 715 is greater than the wall thicknesses of the intermediate and lower sections 810 and 815 of the tubular member 715 in order to optimally facilitate the initiation of the extrusion process and optimally permit the apparatus 10 700 to be positioned in locations in the wellbore having tight clearances.

The outer diameter and wall thickness of the upper section 805 of the tubular member 715 may range, for example, from about 1.05 to 48 inches and $1/8$ to 2 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the upper section 805 of the tubular member 715 range from about 3.5 15 to 16 inches and $3/8$ to 1.5 inches, respectively.

The outer diameter and wall thickness of the intermediate section 810 of the tubular member 715 may range, for example, from about 2.5 to 50 inches and $1/16$ to 1.5 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the intermediate section 810 of the tubular member 715 range 20 from about 3.5 to 19 inches and $1/8$ to 1.25 inches, respectively.

The outer diameter and wall thickness of the lower section 815 of the tubular member 715 may range, for example, from about 2.5 to 50 inches and $1/16$ to 1.25 inches, respectively. In a preferred embodiment, the outer diameter and wall thickness of the lower section 810 of the tubular member 715 range from 25 about 3.5 to 19 inches and $1/8$ to 1.25 inches, respectively. In a particularly preferred embodiment, the wall thickness of the lower section 815 of the tubular member 715 is further increased to increase the strength of the shoe 720 when drillable materials such as, for example, aluminum are used.

The tubular member 715 preferably comprises a solid tubular member. In 30 a preferred embodiment, the end portion 820 of the tubular member 715 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 705 when it completes the extrusion of tubular member 715. In a preferred embodiment, the

length of the tubular member 715 is limited to minimize the possibility of buckling. For typical tubular member 715 materials, the length of the tubular member 715 is preferably limited to between about 40 to 20,000 feet in length.

The shoe 720 is coupled to the expandable mandrel 705 and the tubular
5 member 715. The shoe 720 includes the fluid passage 740. In a preferred embodiment, the shoe 720 further includes an inlet passage 830, and one or more jet ports 835. In a particularly preferred embodiment, the cross-sectional shape of the inlet passage 830 is adapted to receive a latch-down dart, or other similar elements, for blocking the inlet passage 830. The interior of the shoe 720
10 preferably includes a body of solid material 840 for increasing the strength of the shoe 720. In a particularly preferred embodiment, the body of solid material 840 comprises aluminum.

The shoe 720 may comprise any number of conventional commercially available shoes such as, for example, Super Seal II Down-Jet float shoe, or guide
15 shoe with a sealing sleeve for a latch down plug modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the shoe 720 comprises an aluminum down-jet guide shoe with a sealing sleeve for a latch-down plug available from Halliburton Energy Services in Dallas, TX, modified in accordance with the teachings of the present disclosure, in order to optimize
20 guiding the tubular member 715 in the wellbore, optimize the seal between the tubular member 715 and an existing wellbore casing, and to optimally facilitate the removal of the shoe 720 by drilling it out after completion of the extrusion process.

The lower cup seal 725 is coupled to and supported by the support member 745. The lower cup seal 725 prevents foreign materials from entering the interior
25 region of the tubular member 715 above the expandable mandrel 705. The lower cup seal 725 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or Selective Injection Packer (SIP) cups modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the lower cup seal 725 comprises a SIP cup, available from
30 Halliburton Energy Services in Dallas, TX in order to optimally provide a debris barrier and hold a body of lubricant.

The upper cup seal 730 is coupled to and supported by the support member 760. The upper cup seal 730 prevents foreign materials from entering the interior region of the tubular member 715. The upper cup seal 730 may comprise any number of conventional commercially available cup seals such as, for example, TP 5 cups or Selective Injection Packer (SIP) cup modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the upper cup seal 730 comprises a SIP cup available from Halliburton Energy Services in Dallas, TX in order to optimally provide a debris barrier and contain a body of lubricant.

The fluid passage 735 permits fluidic materials to be transported to and 10 from the interior region of the tubular member 715 below the expandable mandrel 705. The fluid passage 735 is fluidically coupled to the fluid passage 740. The fluid passage 735 is preferably coupled to and positioned within the support member 760, the support member 745, the mandrel container 710, and the expandable mandrel 705. The fluid passage 735 preferably extends from a position adjacent 15 to the surface to the bottom of the expandable mandrel 705. The fluid passage 735 is preferably positioned along a centerline of the apparatus 700. The fluid passage 735 is preferably selected to transport materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 40 to 3,000 gallons/minute and 500 to 9,000 psi in order to provide sufficient operating pressures to extrude 20 the tubular member 715 off of the expandable mandrel 705.

As described above with reference to Figs. 1-6, during placement of the apparatus 700 within a new section of a wellbore, fluidic materials forced up the fluid passage 735 can be released into the wellbore above the tubular member 715. In a preferred embodiment, the apparatus 700 further includes a pressure release 25 passage that is coupled to and positioned within the support member 260. The pressure release passage is further fluidically coupled to the fluid passage 735. The pressure release passage preferably includes a control valve for controllably opening and closing the fluid passage. In a preferred embodiment, the control valve is pressure activated in order to controllably minimize surge pressures. The 30 pressure release passage is preferably positioned substantially orthogonal to the centerline of the apparatus 700. The pressure release passage is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates

and pressures ranging from about 0 to 500 gallons/minute and 0 to 1,000 psi in order to reduce the drag on the apparatus 700 during insertion into a new section of a wellbore and to minimize surge pressures on the new wellbore section.

The fluid passage 740 permits fluidic materials to be transported to and
5 from the region exterior to the tubular member 715. The fluid passage 740 is preferably coupled to and positioned within the shoe 720 in fluidic communication with the interior region of the tubular member 715 below the expandable mandrel 705. The fluid passage 740 preferably has a cross-sectional shape that permits a plug, or other similar device, to be placed in the inlet 830 of the fluid passage 740
10 to thereby block further passage of fluidic materials. In this manner, the interior region of the tubular member 715 below the expandable mandrel 705 can be optimally fluidically isolated from the region exterior to the tubular member 715. This permits the interior region of the tubular member 715 below the expandable mandrel 205 to be pressurized.

15 The fluid passage 740 is preferably positioned substantially along the centerline of the apparatus 700. The fluid passage 740 is preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally fill an annular region between the tubular member 715 and a new
20 section of a wellbore with fluidic materials. In a preferred embodiment, the fluid passage 740 includes an inlet passage 830 having a geometry that can receive a dart and/or a ball sealing member. In this manner, the fluid passage 240 can be sealed off by introducing a plug, dart and/or ball sealing elements into the fluid passage 230.

25 In a preferred embodiment, the apparatus 700 further includes one or more seals 845 coupled to and supported by the end portion 820 of the tubular member 715. The seals 845 are further positioned on an outer surface of the end portion 820 of the tubular member 715. The seals 845 permit the overlapping joint between an end portion of preexisting casing and the end portion 820 of the
30 tubular member 715 to be fluidically sealed. The seals 845 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the

present disclosure. In a preferred embodiment, the seals 845 comprise seals molded from StrataLock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a hydraulic seal and a load bearing interference fit in the overlapping joint between the tubular member 715 and an existing casing with optimal load bearing capacity to support the tubular member 715.

In a preferred embodiment, the seals 845 are selected to provide a sufficient frictional force to support the expanded tubular member 715 from the existing casing. In a preferred embodiment, the frictional force provided by the seals 845 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 715.

The support member 745 is preferably coupled to the expandable mandrel 705 and the overshot connection 755. The support member 745 preferably comprises an annular member having sufficient strength to carry the apparatus 700 into a new section of a wellbore. The support member 745 may comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubular modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the support member 745 comprises conventional drill pipe available from various steel mills in the United States.

In a preferred embodiment, a body of lubricant 750 is provided in the annular region above the expandable mandrel container 710 within the interior of the tubular member 715. In this manner, the extrusion of the tubular member 715 off of the expandable mandrel 705 is facilitated. The lubricant 705 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants, or Climax 1500 Antisieze (S100). In a preferred embodiment, the lubricant 750 comprises Climax 1500 Antisieze (S100) available from Halliburton Energy Services in Houston, TX in order to optimally provide lubrication to facilitate the extrusion process.

The overshot connection 755 is coupled to the support member 745 and the support member 760. The overshot connection 755 preferably permits the support

member 745 to be removably coupled to the support member 760. The overshot connection 755 may comprise any number of conventional commercially available overshot connections such as, for example, Innerstring Sealing Adapter, Innerstring Flat-Face Sealing Adapter or EZ Drill Setting Tool Stinger. In a 5 preferred embodiment, the overshot connection 755 comprises a Innerstring Adapter with an Upper Guide available from Halliburton Energy Services in Dallas, TX.

The support member 760 is preferably coupled to the overshot connection 755 and a surface support structure (not illustrated). The support member 760 10 preferably comprises an annular member having sufficient strength to carry the apparatus 700 into a new section of a wellbore. The support member 760 may comprise any number of conventional commercially available support members such as, for example, steel drill pipe, coiled tubing or other high strength tubulars modified in accordance with the teachings of the present disclosure. In a preferred 15 embodiment, the support member 760 comprises a conventional drill pipe available from steel mills in the United States.

The stabilizer 765 is preferably coupled to the support member 760. The stabilizer 765 also preferably stabilizes the components of the apparatus 700 within the tubular member 715. The stabilizer 765 preferably comprises a 20 spherical member having an outside diameter that is about 80 to 99% of the interior diameter of the tubular member 715 in order to optimally minimize buckling of the tubular member 715. The stabilizer 765 may comprise any number of conventional commercially available stabilizers such as, for example, EZ Drill Star Guides, packer shoes or drag blocks modified in accordance with the teachings 25 of the present disclosure. In a preferred embodiment, the stabilizer 765 comprises a sealing adapter upper guide available from Halliburton Energy Services in Dallas, TX.

In a preferred embodiment, the support members 745 and 760 are thoroughly cleaned prior to assembly to the remaining portions of the apparatus 30 700. In this manner, the introduction of foreign material into the apparatus 700 is minimized. This minimizes the possibility of foreign material clogging the various flow passages and valves of the apparatus 700.

In a preferred embodiment, before or after positioning the apparatus 700 within a new section of a wellbore, a couple of wellbore volumes are circulated through the various flow passages of the apparatus 700 in order to ensure that no foreign materials are located within the wellbore that might clog up the various
5 flow passages and valves of the apparatus 700 and to ensure that no foreign material interferes with the expansion mandrel 705 during the expansion process.

In a preferred embodiment, the apparatus 700 is operated substantially as described above with reference to Figs. 1-7 to form a new section of casing within a wellbore.

10 As illustrated in Fig. 8, in an alternative preferred embodiment, the method and apparatus described herein is used to repair an existing wellbore casing 805 by forming a tubular liner 810 inside of the existing wellbore casing 805. In a preferred embodiment, an outer annular lining of cement is not provided in the repaired section. In the alternative preferred embodiment, any number of fluidic
15 materials can be used to expand the tubular liner 810 into intimate contact with the damaged section of the wellbore casing such as, for example, cement, epoxy, slag mix, or drilling mud. In the alternative preferred embodiment, sealing members 815 are preferably provided at both ends of the tubular member in order to optimally provide a fluidic seal. In an alternative preferred embodiment, the
20 tubular liner 810 is formed within a horizontally positioned pipeline section, such as those used to transport hydrocarbons or water, with the tubular liner 810 placed in an overlapping relationship with the adjacent pipeline section. In this manner, underground pipelines can be repaired without having to dig out and replace the damaged sections.

25 In another alternative preferred embodiment, the method and apparatus described herein is used to directly line a wellbore with a tubular liner 810. In a preferred embodiment, an outer annular lining of cement is not provided between the tubular liner 810 and the wellbore. In the alternative preferred embodiment, any number of fluidic materials can be used to expand the tubular liner 810 into
30 intimate contact with the wellbore such as, for example, cement, epoxy, slag mix, or drilling mud.

Referring now to Figs. 9, 9a, 9b and 9c, a preferred embodiment of an apparatus 900 for forming a wellbore casing includes an expandible tubular member 902, a support member 904, an expandible mandrel or pig 906, and a shoe 908. In a preferred embodiment, the design and construction of the mandrel 906 and shoe 908 permits easy removal of those elements by drilling them out. In this manner, the assembly 900 can be easily removed from a wellbore using a conventional drilling apparatus and corresponding drilling methods.

The expandible tubular member 902 preferably includes an upper portion 910, an intermediate portion 912 and a lower portion 914. During operation of the apparatus 900, the tubular member 902 is preferably extruded off of the mandrel 906 by pressurizing an interior region 966 of the tubular member 902. The tubular member 902 preferably has a substantially annular cross-section.

In a particularly preferred embodiment, an expandable tubular member 915 is coupled to the upper portion 910 of the expandable tubular member 902. During operation of the apparatus 900, the tubular member 915 is preferably extruded off of the mandrel 906 by pressurizing the interior region 966 of the tubular member 902. The tubular member 915 preferably has a substantially annular cross-section. In a preferred embodiment, the wall thickness of the tubular member 915 is greater than the wall thickness of the tubular member 902.

The tubular member 915 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steels, titanium or stainless steels. In a preferred embodiment, the tubular member 915 is fabricated from oilfield tubulars in order to optimally provide approximately the same mechanical properties as the tubular member 902. In a particularly preferred embodiment, the tubular member 915 has a plastic yield point ranging from about 40,000 to 135,000 psi in order to optimally provide approximately the same yield properties as the tubular member 902. The tubular member 915 may comprise a plurality of tubular members coupled end to end.

In a preferred embodiment, the upper end portion of the tubular member 915 includes one or more sealing members for optimally providing a fluidic and/or gaseous seal with an existing section of wellbore casing.

In a preferred embodiment, the combined length of the tubular members 902 and 915 are limited to minimize the possibility of buckling. For typical tubular member materials, the combined length of the tubular members 902 and 915 are limited to between about 40 to 20,000 feet in length.

5 The lower portion 914 of the tubular member 902 is preferably coupled to the shoe 908 by a threaded connection 968. The intermediate portion 912 of the tubular member 902 preferably is placed in intimate sliding contact with the mandrel 906.

The tubular member 902 may be fabricated from any number of
10 conventional commercially available materials such as, for example, oilfield tubulars, low alloy steels, titanium or stainless steels. In a preferred embodiment, the tubular member 902 is fabricated from oilfield tubulars in order to optimally provide approximately the same mechanical properties as the tubular member 915. In a particularly preferred embodiment, the tubular member 902 has a plastic yield
15 point ranging from about 40,000 to 135,000 psi in order to optimally provide approximately the same yield properties as the tubular member 915.

The wall thickness of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 may range, for example, from about 1/16 to 1.5 inches. In a preferred embodiment, the wall thickness of the upper, intermediate,
20 and lower portions, 910, 912 and 914 of the tubular member 902 range from about 1/8 to 1.25 in order to optimally provide wall thickness that are about the same as the tubular member 915. In a preferred embodiment, the wall thickness of the lower portion 914 is less than or equal to the wall thickness of the upper portion 910 in order to optimally provide a geometry that will fit into tight clearances
25 downhole.

The outer diameter of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 may range, for example, from about 1.05 to 48 inches. In a preferred embodiment, the outer diameter of the upper, intermediate, and lower portions, 910, 912 and 914 of the tubular member 902 range from about
30 3 1/4 to 19 inches in order to optimally provide the ability to expand the most commonly used oilfield tubulars.

The length of the tubular member 902 is preferably limited to between about 2 to 5 feet in order to optimally provide enough length to contain the mandrel 906 and a body of lubricant.

The tubular member 902 may comprise any number of conventional
5 commercially available tubular members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the tubular member 902 comprises Oilfield Country Tubular Goods available from various U.S. steel mills. The tubular member 915 may comprise any number of conventional commercially available tubular members modified in accordance with the teachings of the
10 present disclosure. In a preferred embodiment, the tubular member 915 comprises Oilfield Country Tubular Goods available from various U.S. steel mills.

The various elements of the tubular member 902 may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece. In a preferred embodiment, the various
15 elements of the tubular member 902 are coupled using welding. The tubular member 902 may comprise a plurality of tubular elements that are coupled end to end. The various elements of the tubular member 915 may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece. In a preferred embodiment, the various
20 elements of the tubular member 915 are coupled using welding. The tubular member 915 may comprise a plurality of tubular elements that are coupled end to end. The tubular members 902 and 915 may be coupled using any number of conventional process such as, for example, threaded connections, welding or machined from one piece.

25 The support member 904 preferably includes an innerstring adapter 916, a fluid passage 918, an upper guide 920, and a coupling 922. During operation of the apparatus 900, the support member 904 preferably supports the apparatus 900 during movement of the apparatus 900 within a wellbore. The support member 904 preferably has a substantially annular cross-section.

30 The support member 904 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel, coiled tubing or stainless steel. In a preferred

embodiment, the support member 904 is fabricated from low alloy steel in order to optimally provide high yield strength.

The innerstring adaptor 916 preferably is coupled to and supported by a conventional drill string support from a surface location. The innerstring adaptor 5 916 may be coupled to a conventional drill string support 971 by a threaded connection 970.

The fluid passage 918 is preferably used to convey fluids and other materials to and from the apparatus 900. In a preferred embodiment, the fluid passage 918 is fluidically coupled to the fluid passage 952. In a preferred embodiment, the fluid 10 passage 918 is used to convey hardenable fluidic sealing materials to and from the apparatus 900. In a particularly preferred embodiment, the fluid passage 918 may include one or more pressure relief passages (not illustrated) to release fluid pressure during positioning of the apparatus 900 within a wellbore. In a preferred embodiment, the fluid passage 918 is positioned along a longitudinal centerline of 15 the apparatus 900. In a preferred embodiment, the fluid passage 918 is selected to permit the conveyance of hardenable fluidic materials at operating pressures ranging from about 0 to 9,000 psi.

The upper guide 920 is coupled to an upper portion of the support member 904. The upper guide 920 preferably is adapted to center the support member 904 20 within the tubular member 915. The upper guide 920 may comprise any number of conventional guide members modified in accordance with the teachings of the present disclosure. In a preferred embodiment, the upper guide 920 comprises an innerstring adapter available from Halliburton Energy Services in Dallas, TX order to optimally guide the apparatus 900 within the tubular member 915.

25 The coupling 922 couples the support member 904 to the mandrel 906. The coupling 922 preferably comprises a conventional threaded connection.

The various elements of the support member 904 may be coupled using any number of conventional processes such as, for example, welding, threaded connections or machined from one piece. In a preferred embodiment, the various 30 elements of the support member 904 are coupled using threaded connections.

The mandrel 906 preferably includes a retainer 924, a rubber cup 926, an expansion cone 928, a lower cone retainer 930, a body of cement 932, a lower guide

934, an extension sleeve 936, a spacer 938, a housing 940, a sealing sleeve 942, an upper cone retainer 944, a lubricator mandrel 946, a lubricator sleeve 948, a guide 950, and a fluid passage 952.

The retainer 924 is coupled to the lubricator mandrel 946, lubricator sleeve 5 948, and the rubber cup 926. The retainer 924 couples the rubber cup 926 to the lubricator sleeve 948. The retainer 924 preferably has a substantially annular cross-section. The retainer 924 may comprise any number of conventional commercially available retainers such as, for example, slotted spring pins or roll pin.

10 The rubber cup 926 is coupled to the retainer 924, the lubricator mandrel 946, and the lubricator sleeve 948. The rubber cup 926 prevents the entry of foreign materials into the interior region 972 of the tubular member 902 below the rubber cup 926. The rubber cup 926 may comprise any number of conventional commercially available rubber cups such as, for example, TP cups or Selective 15 Injection Packer (SIP) cup. In a preferred embodiment, the rubber cup 926 comprises a SIP cup available from Halliburton Energy Services in Dallas, TX in order to optimally block foreign materials.

In a particularly preferred embodiment, a body of lubricant is further provided in the interior region 972 of the tubular member 902 in order to lubricate 20 the interface between the exterior surface of the mandrel 902 and the interior surface of the tubular members 902 and 915. The lubricant may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antiseize (3100). In a preferred embodiment, the lubricant comprises Climax 1500 Antiseize 25 (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide lubrication to facilitate the extrusion process.

The expansion cone 928 is coupled to the lower cone retainer 930, the body of cement 932, the lower guide 934, the extension sleeve 936, the housing 940, and the upper cone retainer 944. In a preferred embodiment, during operation of the 30 apparatus 900, the tubular members 902 and 915 are extruded off of the outer surface of the expansion cone 928. In a preferred embodiment, axial movement of the expansion cone 928 is prevented by the lower cone retainer 930, housing 940

and the upper cone retainer 944. Inner radial movement of the expansion cone 928 is prevented by the body of cement 932, the housing 940, and the upper cone retainer 944.

The expansion cone 928 preferably has a substantially annular cross section.

- 5 The outside diameter of the expansion cone 928 is preferably tapered to provide a cone shape. The wall thickness of the expansion cone 928 may range, for example, from about 0.125 to 3 inches. In a preferred embodiment, the wall thickness of the expansion cone 928 ranges from about 0.25 to 0.75 inches in order to optimally provide adequate compressive strength with minimal material. The
- 10 maximum and minimum outside diameters of the expansion cone 928 may range, for example, from about 1 to 47 inches. In a preferred embodiment, the maximum and minimum outside diameters of the expansion cone 928 range from about 3.5 to 19 in order to optimally provide expansion of generally available oilfield tubulars

- The expansion cone 928 may be fabricated from any number of conventional
- 15 commercially available materials such as, for example, ceramic, tool steel, titanium or low alloy steel. In a preferred embodiment, the expansion cone 928 is fabricated from tool steel in order to optimally provide high strength and abrasion resistance. The surface hardness of the outer surface of the expansion cone 928 may range, for example, from about 50 Rockwell C to 70 Rockwell C. In a preferred embodiment,
- 20 the surface hardness of the outer surface of the expansion cone 928 ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. In a preferred embodiment, the expansion cone 928 is heat treated to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness.

- 25 The lower cone retainer 930 is coupled to the expansion cone 928 and the housing 940. In a preferred embodiment, axial movement of the expansion cone 928 is prevented by the lower cone retainer 930. Preferably, the lower cone retainer 930 has a substantially annular cross-section.

- The lower cone retainer 930 may be fabricated from any number of
- 30 conventional commercially available materials such as, for example, ceramic, tool steel, titanium or low alloy steel. In a preferred embodiment, the lower cone retainer 930 is fabricated from tool steel in order to optimally provide high

strength and abrasion resistance. The surface hardness of the outer surface of the lower cone retainer 930 may range, for example, from about 50 Rockwell C to 70 Rockwell C. In a preferred embodiment, the surface hardness of the outer surface of the lower cone retainer 930 ranges from about 58 Rockwell C to 62 Rockwell C
5 in order to optimally provide high yield strength. In a preferred embodiment, the lower cone retainer 930 is heat treated to optimally provide a hard outer surface and a resilient interior body in order to optimally provide abrasion resistance and fracture toughness.

In a preferred embodiment, the lower cone retainer 930 and the expansion
10 cone 928 are formed as an integral one-piece element in order to reduce the number of components and increase the overall strength of the apparatus. The outer surface of the lower cone retainer 930 preferably mates with the inner surfaces of the tubular members 902 and 915.

The body of cement 932 is positioned within the interior of the mandrel 906.
15 The body of cement 932 provides an inner bearing structure for the mandrel 906. The body of cement 932 further may be easily drilled out using a conventional drill device. In this manner, the mandrel 906 may be easily removed using a conventional drilling device.

The body of cement 932 may comprise any number of conventional
20 commercially available cement compounds. Alternatively, aluminum, cast iron or some other drillable metallic, composite, or aggregate material may be substituted for cement. The body of cement 932 preferably has a substantially annular cross-section.

The lower guide 934 is coupled to the extension sleeve 936 and housing 940.
25 During operation of the apparatus 900, the lower guide 934 preferably helps guide the movement of the mandrel 906 within the tubular member 902. The lower guide 934 preferably has a substantially annular cross-section.

The lower guide 934 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy
30 steel or stainless steel. In a preferred embodiment, the lower guide 934 is fabricated from low alloy steel in order to optimally provide high yield strength.

The outer surface of the lower guide 934 preferably mates with the inner surface of the tubular member 902 to provide a sliding fit.

The extension sleeve 936 is coupled to the lower guide 934 and the housing 940. During operation of the apparatus 900, the extension sleeve 936 preferably helps guide the movement of the mandrel 906 within the tubular member 902. The extension sleeve 936 preferably has a substantially annular cross-section.

The extension sleeve 936 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In a preferred embodiment, the extension sleeve 936 is fabricated from low alloy steel in order to optimally provide high yield strength. The outer surface of the extension sleeve 936 preferably mates with the inner surface of the tubular member 902 to provide a sliding fit. In a preferred embodiment, the extension sleeve 936 and the lower guide 934 are formed as an integral one-piece element in order to minimize the number of components and increase the strength of the apparatus.

The spacer 938 is coupled to the sealing sleeve 942. The spacer 938 preferably includes the fluid passage 952 and is adapted to mate with the extension tube 960 of the shoe 908. In this manner, a plug or dart can be conveyed from the surface through the fluid passages 918 and 952 into the fluid passage 962. Preferably, the spacer 938 has a substantially annular cross-section.

The spacer 938 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the spacer 938 is fabricated from aluminum in order to optimally provide drillability. The end of the spacer 938 preferably mates with the end of the extension tube 960. In a preferred embodiment, the spacer 938 and the sealing sleeve 942 are formed as an integral one-piece element in order to reduce the number of components and increase the strength of the apparatus.

The housing 940 is coupled to the lower guide 934, extension sleeve 936, expansion cone 928, body of cement 932, and lower cone retainer 930. During operation of the apparatus 900, the housing 940 preferably prevents inner radial motion of the expansion cone 928. Preferably, the housing 940 has a substantially annular cross-section.

The housing 940 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield tubulars, low alloy steel or stainless steel. In a preferred embodiment, the housing 940 is fabricated from low alloy steel in order to optimally provide high yield strength. In a 5 preferred embodiment, the lower guide 934, extension sleeve 936 and housing 940 are formed as an integral one-piece element in order to minimize the number of components and increase the strength of the apparatus.

In a particularly preferred embodiment, the interior surface of the housing 940 includes one or more protrusions to facilitate the connection between the 10 housing 940 and the body of cement 932.

The sealing sleeve 942 is coupled to the support member 904, the body of cement 932, the spacer 938, and the upper cone retainer 944. During operation of the apparatus, the sealing sleeve 942 preferably provides support for the mandrel 906. The sealing sleeve 942 is preferably coupled to the support member 904 using 15 the coupling 922. Preferably, the sealing sleeve 942 has a substantially annular cross-section.

The sealing sleeve 942 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the sealing sleeve 942 is fabricated from 20 aluminum in order to optimally provide drillability of the sealing sleeve 942.

In a particularly preferred embodiment, the outer surface of the sealing sleeve 942 includes one or more protrusions to facilitate the connection between the sealing sleeve 942 and the body of cement 932.

In a particularly preferred embodiment, the spacer 938 and the sealing 25 sleeve 942 are integrally formed as a one-piece element in order to minimize the number of components.

The upper cone retainer 944 is coupled to the expansion cone 928, the sealing sleeve 942, and the body of cement 932. During operation of the apparatus 900, the upper cone retainer 944 preferably prevents axial motion of the expansion 30 cone 928. Preferably, the upper cone retainer 944 has a substantially annular cross-section.

The upper cone retainer 944 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the upper cone retainer 944 is fabricated from aluminum in order to optimally provide drillability of the upper
5 cone retainer 944.

In a particularly preferred embodiment, the upper cone retainer 944 has a cross-sectional shape designed to provide increased rigidity. In a particularly preferred embodiment, the upper cone retainer 944 has a cross-sectional shape that is substantially I-shaped to provide increased rigidity and minimize the
10 amount of material that would have to be drilled out.

The lubricator mandrel 946 is coupled to the retainer 924, the rubber cup 926, the upper cone retainer 944, the lubricator sleeve 948, and the guide 950. During operation of the apparatus 900, the lubricator mandrel 946 preferably contains the body of lubricant in the annular region 972 for lubricating the
15 interface between the mandrel 906 and the tubular member 902. Preferably, the lubricator mandrel 946 has a substantially annular cross-section.

The lubricator mandrel 946 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the lubricator mandrel 946 is
20 fabricated from aluminum in order to optimally provide drillability of the lubricator mandrel 946.

The lubricator sleeve 948 is coupled to the lubricator mandrel 946, the retainer 924, the rubber cup 926, the upper cone retainer 944, the lubricator sleeve 948, and the guide 950. During operation of the apparatus 900, the lubricator
25 sleeve 948 preferably supports the rubber cup 926. Preferably, the lubricator sleeve 948 has a substantially annular cross-section.

The lubricator sleeve 948 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the lubricator sleeve 948 is
30 fabricated from aluminum in order to optimally provide drillability of the lubricator sleeve 948.

As illustrated in Fig. 9c, the lubricator sleeve 948 is supported by the lubricator mandrel 946. The lubricator sleeve 948 in turn supports the rubber cup 926. The retainer 924 couples the rubber cup 926 to the lubricator sleeve 948. In a preferred embodiment, seals 949a and 949b are provided between the lubricator
5 mandrel 946, lubricator sleeve 948, and rubber cup 926 in order to optimally seal off the interior region 972 of the tubular member 902.

The guide 950 is coupled to the lubricator mandrel 946, the retainer 924, and the lubricator sleeve 948. During operation of the apparatus 900, the guide 950 preferably guides the apparatus on the support member 904. Preferably, the
10 guide 950 has a substantially annular cross-section.

The guide 950 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the guide 950 is fabricated from aluminum order to optimally provide drillability of the guide 950.

15 The fluid passage 952 is coupled to the mandrel 906. During operation of the apparatus, the fluid passage 952 preferably conveys hardenable fluidic materials. In a preferred embodiment, the fluid passage 952 is positioned about the centerline of the apparatus 900. In a particularly preferred embodiment, the fluid passage 952 is adapted to convey hardenable fluidic materials at pressures
20 and flow rate ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/min in order to optimally provide pressures and flow rates to displace and circulate fluids during the installation of the apparatus 900.

The various elements of the mandrel 906 may be coupled using any number of conventional process such as, for example, threaded connections, welded
25 connections or cementing. In a preferred embodiment, the various elements of the mandrel 906 are coupled using threaded connections and cementing.

The shoe 908 preferably includes a housing 954, a body of cement 956, a sealing sleeve 958, an extension tube 960, a fluid passage 962, and one or more outlet jets 964.

30 The housing 954 is coupled to the body of cement 956 and the lower portion 914 of the tubular member 902. During operation of the apparatus 900, the housing 954 preferably couples the lower portion of the tubular member 902 to the

shoe 908 to facilitate the extrusion and positioning of the tubular member 902. Preferably, the housing 954 has a substantially annular cross-section.

The housing 954 may be fabricated from any number of conventional commercially available materials such as, for example, steel or aluminum. In a preferred embodiment, the housing 954 is fabricated from aluminum in order to optimally provide drillability of the housing 954.

In a particularly preferred embodiment, the interior surface of the housing 954 includes one or more protrusions to facilitate the connection between the body of cement 956 and the housing 954.

10 The body of cement 956 is coupled to the housing 954, and the sealing sleeve 958. In a preferred embodiment, the composition of the body of cement 956 is selected to permit the body of cement to be easily drilled out using conventional drilling machines and processes.

15 The composition of the body of cement 956 may include any number of conventional cement compositions. In an alternative embodiment, a drillable material such as, for example, aluminum or iron may be substituted for the body of cement 956.

20 The sealing sleeve 958 is coupled to the body of cement 956, the extension tube 960, the fluid passage 962, and one or more outlet jets 964. During operation of the apparatus 900, the sealing sleeve 958 preferably is adapted to convey a hardenable fluidic material from the fluid passage 952 into the fluid passage 962 and then into the outlet jets 964 in order to inject the hardenable fluidic material into an annular region external to the tubular member 902. In a preferred embodiment, during operation of the apparatus 900, the sealing sleeve 958 further
25 includes an inlet geometry that permits a conventional plug or dart 974 to become lodged in the inlet of the sealing sleeve 958. In this manner, the fluid passage 962 may be blocked thereby fluidically isolating the interior region 966 of the tubular member 902.

30 In a preferred embodiment, the sealing sleeve 958 has a substantially annular cross-section. The sealing sleeve 958 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the sealing sleeve 958 is

fabricated from aluminum in order to optimally provide drillability of the sealing sleeve 958.

The extension tube 960 is coupled to the sealing sleeve 958, the fluid passage 962, and one or more outlet jets 964. During operation of the apparatus 900, the extension tube 960 preferably is adapted to convey a hardenable fluidic material from the fluid passage 952 into the fluid passage 962 and then into the outlet jets 964 in order to inject the hardenable fluidic material into an annular region external to the tubular member 902. In a preferred embodiment, during operation of the apparatus 900, the sealing sleeve 960 further includes an inlet geometry that permits a conventional plug or dart 974 to become lodged in the inlet of the sealing sleeve 958. In this manner, the fluid passage 962 is blocked thereby fluidically isolating the interior region 968 of the tubular member 902. In a preferred embodiment, one end of the extension tube 960 mates with one end of the spacer 938 in order to optimally facilitate the transfer of material between the two.

In a preferred embodiment, the extension tube 960 has a substantially annular cross-section. The extension tube 960 may be fabricated from any number of conventional commercially available materials such as, for example, steel, aluminum or cast iron. In a preferred embodiment, the extension tube 960 is fabricated from aluminum in order to optimally provide drillability of the extension tube 960.

The fluid passage 962 is coupled to the sealing sleeve 958, the extension tube 960, and one or more outlet jets 964. During operation of the apparatus 900, the fluid passage 962 is preferably conveys hardenable fluidic materials. In a preferred embodiment, the fluid passage 962 is positioned about the centerline of the apparatus 900. In a particularly preferred embodiment, the fluid passage 962 is adapted to convey hardenable fluidic materials at pressures and flow rate ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/min in order to optimally provide fluids at operationally efficient rates.

The outlet jets 964 are coupled to the sealing sleeve 958, the extension tube 960, and the fluid passage 962. During operation of the apparatus 900, the outlet jets 964 preferably convey hardenable fluidic material from the fluid passage 962

to the region exterior of the apparatus 900. In a preferred embodiment, the shoe 908 includes a plurality of outlet jets 964.

In a preferred embodiment, the outlet jets 964 comprise passages drilled in the housing 954 and the body of cement 956 in order to simplify the construction 5 of the apparatus 900.

The various elements of the shoe 908 may be coupled using any number of conventional process such as, for example, threaded connections, cement or machined from one piece of material. In a preferred embodiment, the various elements of the shoe 908 are coupled using cement.

10 In a preferred embodiment, the assembly 900 is operated substantially as described above with reference to Figs. 1-8 to create a new section of casing in a wellbore or to repair a wellbore casing or pipeline.

In particular, in order to extend a wellbore into a subterranean formation, a drill string is used in a well known manner to drill out material from the 15 subterranean formation to form a new section.

The apparatus 900 for forming a wellbore casing in a subterranean formation is then positioned in the new section of the wellbore. In a particularly preferred embodiment, the apparatus 900 includes the tubular member 916. In a preferred embodiment, a hardenable fluidic sealing hardenable fluidic sealing 20 material is then pumped from a surface location into the fluid passage 918. The hardenable fluidic sealing material then passes from the fluid passage 918 into the interior region 966 of the tubular member 902 below the mandrel 906. The hardenable fluidic sealing material then passes from the interior region 966 into the fluid passage 962. The hardenable fluidic sealing material then exits the 25 apparatus 900 via the outlet jets 964 and fills an annular region between the exterior of the tubular member 902 and the interior wall of the new section of the wellbore. Continued pumping of the hardenable fluidic sealing material causes the material to fill up at least a portion of the annular region.

The hardenable fluidic sealing material is preferably pumped into the 30 annular region at pressures and flow rates ranging, for example, from about 0 to 5,000 psi and 0 to 1,500 gallons/min, respectively. In a preferred embodiment, the hardenable fluidic sealing material is pumped into the annular region at pressures

and flow rates that are designed for the specific wellbore section in order to optimize the displacement of the hardenable fluidic sealing material while not creating high enough circulating pressures such that circulation might be lost and that could cause the wellbore to collapse. The optimum pressures and flow rates
5 are preferably determined using conventional empirical methods.

The hardenable fluidic sealing material may comprise any number of conventional commercially available hardenable fluidic sealing materials such as, for example, slag mix, cement or epoxy. In a preferred embodiment, the hardenable fluidic sealing material comprises blended cements designed
10 specifically for the well section being lined available from Halliburton Energy Services in Dallas, TX in order to optimally provide support for the new tubular member while also maintaining optimal flow characteristics so as to minimize operational difficulties during the displacement of the cement in the annular region. The optimum composition of the blended cements is preferably determined
15 using conventional empirical methods.

The annular region preferably is filled with the hardenable fluidic sealing material in sufficient quantities to ensure that, upon radial expansion of the tubular member 902, the annular region of the new section of the wellbore will be filled with hardenable material.

20 Once the annular region has been adequately filled with hardenable fluidic sealing material, a plug or dart 974, or other similar device, preferably is introduced into the fluid passage 962 thereby fluidically isolating the interior region 966 of the tubular member 902 from the external annular region. In a preferred embodiment, a non hardenable fluidic material is then pumped into the interior
25 region 966 causing the interior region 966 to pressurize. In a particularly preferred embodiment, the plug or dart 974, or other similar device, preferably is introduced into the fluid passage 962 by introducing the plug or dart 974, or other similar device into the non hardenable fluidic material. In this manner, the amount of cured material within the interior of the tubular members 902 and 915
30 is minimized.

Once the interior region 966 becomes sufficiently pressurized, the tubular members 902 and 915 are extruded off of the mandrel 906. The mandrel 906 may